Center for the Advancement of Energy Markets

Estimating the Benefits of Restructuring Electricity Markets:
An Application to the PJM Region

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Executive Summary

This study estimates the benefits from restructuring the electricity market in the PJM[1] region. Benefits are estimated to reflect current restructuring efforts, not future efforts. Current restructuring efforts have reduced the price of electricity to ultimate customers. This price decline produces current benefits to customers plus an additional benefit that will accrue in the indefinite future. These future benefits are summed and discounted to produce a present value estimate of the benefit of current restructuring efforts. Hence, the benefit estimated in this study is the direct increase in economic value to ultimate customers resulting primarily from the decline in electricity prices from 1997 through 2002. Additional macroeconomic benefits are likely to double the direct customer benefits.

The table on the following page depicts the PJM states and the three sectors of ultimate customers: residential, commercial and industrial. The second column shows electricity costs by state and sector in year 2002 measured in constant dollars. As depicted in the next column, ultimate customers in the PJM region saved about $3.2 billion in 2002 from current restructuring efforts. This saving is about 15 percent of their 2002 electricity bill. For instance, residential households in Pennsylvania saved, on average, about $117 on their electric bill in year 2002.[2] Additional saving will occur in the indefinite future. The value of future saving is summed and discounted to the present and is estimated to be $28.5 billion, These future savings exceed total electricity costs for the year 2002 ($22 billion).[3] Each household in PA will save, on average, about $1,262, measured as present value of the sum of future saving.[4]

The last column shows the present value of this future saving relative to 2002 electricity expenses. On average, ultimate customers in the PJM region may obtain total lifetime dollar savings from current restructuring efforts that exceed their electricity bill for a single year. For some lower income households, the saving in their annual electric bill will exceed the saving resulting from the

[1] The PJM region considered here includes: PA, NJ, MD, DE and DC. The PJM region was expanded in 2002 to include parts of OH, WV and VA that are served by Allegheny Power Co.
[2] The table shows savings in the PA residential sector to be $558.22 million in year 2002, and there were 4.777 million households in PA in year 2000, for an average saving of $117 per household in 2002. Household data are obtained from the U.S. Bureau of Census, *Statistical Abstract in the United States,2002*, Washington DC, Table No. 53, p. 50.
[3] The present value of electricity price declines in the PJM region in constant dollars is $38.7 billion (Tables 4 and A1); however, about $10.2 billion of cost reduction value would have occurred without restructuring.
[4] Lifetime saving per household is estimated as present value of savings in PA in 2002 ($6,027 million) divided by number of households (4.777 million).

2003 federal income tax legislation.[5] The benefits to consumers from restructuring efforts, particularly in the wholesale electricity market, in the PJM region are substantial. By most measures, the PJM model is successful and would be appropriate for other regions in the United States.

As shown in the table, the present value of the reduction in electricity costs in the PJM region differs between states and sectors, but the largest benefit appears in the residential sector. Lower and middle income households spend on average a much larger share of their income on electricity than high income households. Therefore, lower and middle income households are probably the greatest beneficiaries of the PJM restructuring effort.

Savings By State and Sector in PJM Region
(in millions of constant dollars)

[5] Alan Friedlander, "How New Federal Tax law Will Affect Brackets, Bill" *Your Local News, Newspapers Online, September 17, 2003. Friedlander notes that the lowest income households may save only $100 in taxes from the Jobs and Growth Tax Relief Reconciliation Act of 2003.*

	Electricity 2002 Costs $ mil. Real	Cost Saving In 2002 $ mil. Real	Present Value Future Savings 2002, Real	Percent Saving Col. 2/Col. 3
New Jersey				
Residential	$2,464.10	$680.14	$4,633.74	188.05%
Commercial	$2,817.29	$738.89	$5,034.04	178.68%
Industrial	$991.86	$139.02	$947.17	95.49%
Total	$6,359.25	$1,468.34	$10,003.76	157.31%
Pennsylvania				
Residential	$4,394.75	$558.22	$6,027.11	137.14%
Commercial	$3,345.24	$359.04	$4,403.75	131.64%
Industrial	$2,512.59	$261.50	$3,874.61	154.21%
Total	$10,398.06	$993.97	$13,108.83	126.07%
Maryland				
Residential	$1,828.17	$327.49	$2,231.18	122.04%
Commercial	$1,360.61	$143.91	$980.48	72.06%
Industrial	$558.15	$95.37	$649.74	116.41%
Total	$3,826.53	$622.39	$4,240.35	110.81%
Washington DC				
Residential	$138.17	$3.81	$25.93	18.77%
Commercial	$574.62	$67.25	$458.20	79.74%
Industrial	$12.81	-$0.28	-$1.93	-15.07%
Total	$748.47	$74.05	$504.52	67.41%
Delaware				
Residential	$274.50	$51.86	$353.30	128.71%
Commercial	$202.22	$17.65	$120.24	59.46%
Industrial	$164.70	$38.23	$260.43	158.12%
Total	$647.82	$97.62	$665.10	102.67%
Total PJM	$21,980.13	$3,256.38	$28,524.34	129.77%

Source: Derived from Tables A1 and A2

The total United States and three nearby states to the PJM region are also experiencing declining electricity prices in constant dollars. However, the present value of these cost decreases is much less than in the PJM region. The estimates presented in the above table are “relative” cost reductions, because they are over and above the cost reductions that characterize neighboring states and the entire United States. Hence, restructuring efforts in the PJM region are a main contributor to the large declines in electricity prices. The PJM region is thereby gaining an economic advantage relative to states that are not restructuring. As further restructuring is implemented – and payments for stranded costs reduced – the PJM region will realize very large economic benefits, especially relative to other regions which have not restructured their markets.

The estimated present value benefits are the dollar value to ultimate customers from electricity price decreases from 1997 through 2002, and assume that such price decreases remain constant in the future. This assumption is admittedly precarious because there are indications that future cost savings will be larger than estimated here, but other indications of smaller benefits. The trends in the PJM wholesale market are in the direction of increasing efficiencies, which should produce larger future cost saving. The completion of stranded cost recovery will increase benefits to customers over time. The expiration of negotiated retail price decreases will encourage the development of retail competition. Hence, benefits estimated here are likely to be understated.

The estimated cost saving in Maryland typifies the region. Cost saving in the electricity bill in year 2002 is more than 10 percent of the 2002 electricity bill. The largest saving is in the residential sector. Future electricity cost savings from current efforts exceed the year 2002 electricity bill. The electricity cost saving in PA is, in percentage terms a little larger than in MD. Pennsylvania customers are currently receiving a cost reduction benefit from restructuring; even though a substantial share of the benefit is deferred until stranded costs are repaid.

The estimated cost saving to New Jersey customers in year 2002, of about $1.4 billion has been realized, but future benefits are less certain. The decreases in retail prices in New Jersey resulted from a bargain that included initial price declines of 15%. That bargain expired in August 2003, and rates in nominal terms returned to their initial levels. However, the inflation rate from 1997 through 2003 was about 2 percent per year (10% for 5 years), which means that New Jersey customers still have a 10 price decline in electricity rates since 1997 in constant dollars. In addition, with efficiencies achieved in the wholesale PJM market passed forward to customers, some nominal price declines are plausible. The retail price increase in New Jersey in 2003 will provide a much needed incentive towards retail competition, which may ultimately make customers better of than commission mandated price declines. Overall, it appears that with the expiration of the negotiated price declines, New Jersey customers will still see future benefit in constant dollars, but perhaps not as large as in the above table.

The above table presents benefit estimates of restructuring efforts currently in place. On balance, it is likely that the benefits estimates for New Jersey are optimistic. However, the benefit estimates of the other states are probably conservative, and larger benefits are plausible.

The table presents estimates of the benefit of existing restructuring efforts, which are significant; however, even larger benefits will result from future efforts.

This study considers four main sources of benefits: the wholesale market, the retail market, the capacity market, and price-demand response mechanisms. At this point, PJM has successfully restructured much of the wholesale market, which is the main source of the benefit produced so far. The real time and day ahead auction markets implemented by PJM produce significant efficiencies and cost reductions relative to markets subject to traditional utility regulation. The PJM region has been in restructuring mode for about five years and has been highly successful in the wholesale market, with some success in retail markets. With transition costs repaid, price-demand mechanisms implemented, and a robust competitive retail market with product differentiation, the benefits from restructuring should be much larger than obtained from current price declines. Such benefits, when fully realized, should be sufficient to produce some competitive advantage over states that do not successfully restructure.

The market for total capacity does not yet include significant price-demand response, and only small benefits are accruing from this market. The PJM Interchange recognizes the need for efficient pricing. The benefits from efficient pricing are likely to be large, but are still in the future. Retail restructuring is described as a deal that includes stranded cost recovery, negotiated price declines and other factors. Retail competition currently provides some cost reduction benefits to customers, but the main benefit from retail competition will occur when the transition deal is complete and a price-demand mechanism is implemented. The suggested conclusion is that the largest benefit from retail competition, as well as restructuring overall, is in the future.

Under PJM's auction system, reliability has improved in the PJM region. From 1994 through 1997 the forced outage rate averaged about 10 percent, but decreased to about 4.5 percent during 2001 and 2002. The incentives inherent in the PJM wholesale market encourage reliability in capacity and penalize unreliability. The reduced forced outage rate and increased availability are expected efficiency improvements resulting from the design features of the restructured PJM market.

Finally, while difficult to measure, restructuring efforts in the PJM region and within the states themselves are expected to result in a range of non-price benefits. Expected consumer benefits could range from enhanced customer service, more product offerings, new technologies, more billing options and more product and services tailored to individual consumer needs. Due to increased numbers of marketers in the PJM region, consumers are already beginning to see some of the non-price benefits associated with restructuring. For example, consumers are now being offered more "green options" and more billing options than before. However, the expectation is that once retail competition in the Mid-Atlantic states develops fully, these benefits will grow. In fact, as with competition in telecommunications services, there is a reasonable expectation that the largest benefit to consumers from retail competition could be these set of non-price benefits over time rather than simply lower costs.

The PJM region is highly touted for its successful restructuring. This analysis of the PJM wholesale market concurs that such acclaim is warranted. Several factors that explain this success are as follows: (1) the PJM power pool has over 70 years experience that provides a basis for developing a more competitive market, (2) the region applies a well-specified auction market model based on real time and day ahead prices, (3) the PJM region is large enough so that the auction market model is well-functioning, (4) spot prices from the auction market model provide an incentive to attract sufficient investment in generating capacity, (5) authority over wholesale restructuring is with the PJM Interchange and with the FERC, who are strongly committed to developing competitive markets.

The benefits from restructuring in the PJM region result from improving market efficiency and removing some of the inefficiencies associated with the traditional regulation of electric utilities. The benefit estimates are not associated with the level of electricity prices. Hence, the benefits estimated here should apply to other states regardless of electricity prices. Major benefits derive from the PJM power pool because of its real time and day ahead prices for energy, capacity and related markets. The incentives inherent in the auction market encourage cost reduction relative to the incentives inherent in traditional utility regulation. Although restructuring in other states in a more competitive direction would enhance the interest of electricity customers, it may not enhance the self-interest of commissioners and legislators. Restructuring is an economic investment; it requires an upfront commitment of mostly political capital to produce a long term economic payoff. In those states averse to restructuring, the best chance for improved efficiency is probably in the wholesale market. The development of retail competition may require prior demonstrated successes from regions such as PJM.

Biography of Dr. Roland Sutherland

Ron Sutherland is a Ph. D economist with more than 20 years experience analyzing energy issues, including electricity and natural gas markets. Ron began his professional career as an economics professor with the University of Illinois, Springfield, teaching graduate level courses in microeconomics and econometrics. Much of Ron's experience is with two DOE national laboratories: Los Alamos National Laboratory and Argonne National Laboratory, where he assessed several regulatory, environmental and energy policy issues. Ron wrote several articles for Energy Policy and The Energy Journal on utility deregulation, energy conservation (DSM) programs and long-term contracts. Ron was also a senior economist for the American Petroleum Institute (API). While with API, Ron produced reports and articles on the economics of climate change and energy subsidies.

At present, Ron is an independent consulting economist, as well as a Senior Center Scholar at the Center for the Advancement of Energy Markets and Adjunct Professor of Law at the George Mason University, School of Law. Ron provides economic expertise on a variety of energy related issues, but focuses mostly on electricity and natural gas regulatory and restructuring issues. As a Center Scholar for the Center for the Advancement for Energy Markets, Ron wrote a paper "The Role of Default Provider in Restructuring Energy Markets" and has just completed "Estimating the Benefits from Restructuring Electricity Markets: An Application of the PJM Region" Ron can be reached at rsutherland@caem.org and at sutherlandron@hotmail.com.

1. Introduction

The central issue in electricity markets is whether the influence of government in determining prices, investment, and electricity related services should be reduced and replaced by greater reliance on market forces. The United States, and many countries around the world, are restructuring their markets for electricity with the objective of providing direct benefits to customers and additional economic benefits. The purpose of this study is to estimate the net economic benefits resulting from restructuring the market for electricity in the PJM region. Net benefits are estimated for the residential, commercial and industrial sectors, as well as for each state.

Restructuring electricity utility industry in the PJM market is developing in incremental steps, with segments of the market becoming quite competitive, but regulation continuing to affect much of the market. Consequently, the analysis focuses on three specific markets: the wholesale market, the retail market, and the market for total capacity.

Historically, electric utilities were described as a natural monopoly where costs declined continuously with size, where size was measured as capacity of generating unit (MW), or as size of service territory. Given the assumption of economies of scale, customers could obtain lower cost from a regulated monopolist, than from a competitive market. The nature of cost-of-service (COS) regulation is to charge rates that allow utilities to be reimbursed for costs prudently incurred, which include an allowed rate of return on capital investments.

Cost-of-service regulation contains inefficient incentives with respect to investment and pricing. Section 2, explains these inefficiencies from an historical perspective. The regulatory paradigm began reversing during the mid to late 1960s. The newer view is that a restructured market with competitive in generation and retail service would provide greater benefits to ultimate customers. Such a market would provide net benefits to customers and overall benefits to the state or regional economy.

The PJM region considered in this analysis includes: Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia.[6] PJM, as used here, refers to a power pool which is an entity – the PJM Interchange – a limited liability company that manages regional power operations.

This region is selected as a case study area because it is frequently recognized as one of the most successful restructuring efforts in the U.S. Section 3 presents a brief overview of the PJM restructuring effort. The PJM restructuring effort has succeeded in developing real time and day ahead markets for capacity and for energy. This accomplishment argues strongly for the

[6] The PJM region includes: PA, NJ, MD, DE and DC, which is considered here, but parts of OH, VA and WV were added in year 2002, and are not included in this analysis.

occurrence of benefits from competition, because such markets are much more efficient than regulated markets.

Section 4 explains that much of the benefit from restructuring is likely to derive from the wholesale market, primarily with respect to investment and pricing. The benefits of retail competition are discussed briefly. The conventional view is that retail competition will reduce prices to ultimate customers. At present retail competition is achieving some success with price competition. Merchants can however provide product differentiation that includes price-risk management, priority service, energy conservation, and various other energy related services.

In the beginning of this study, participants in a CAEM working group suggested some benefits that result from the PJM restructuring. Section 5 explains how benefits are estimated in mainstream economic analyses and how these benefits correspond with those suggested by the working group. Section 5 also presents the quantitative estimate of benefits. The method used to calculate benefits from restructuring is also applied to the total U.S. and to three nearby states that are not restructuring. The PJM states are receiving significant benefits so far, and the nearby states that are not restructuring are not experiencing comparable electricity price decreases.

Section 6 analyzes the PJM effort to restructure the market for total capacity. This analysis is lengthy because it is intended to provide insights into the challenges of restructuring in addition to the market for total capacity. Total generating capacity is used to meet expected load and to provide a reliable reserve margin. The PJM capacity market thus far has inadequate price-demand response. The analysis in Section 6 uses pubic choice theory to explain that influential groups oppose the use of price-demand response to determine reserve margins. Further, one price–demand response program is not designed to provide a cost-effective load management effort. The challenges in optimizing total capacity, from the perspective of ultimate customers, epitomize the challenges to restructure electricity markets.

2. Electric Utilities and Traditional Utility Regulation

Over the past few decades, the support for traditional methods of regulating electric utilities has changed. Current efforts to restructure the electric utility industry are based in part on the view that traditional regulation results in an economically inefficient use of resources. The initial rationale for traditional regulation was based on natural monopoly. However, most observers now recognize that traditional regulation produces market outcomes different from competitive markets. Consequently restructuring electric utility markets could increase economic efficiency which would enhance the economic well-being of ultimate customers.

Historically, most electricity in the United States was produced and sold by investor-owned utilities that operated within their service territories. Electric utilities were vertically integrated and performed three basic functions: generation, distribution and transmission. The generation function uses a fuel, such as coal or natural gas, and a central power station to produce electricity. The amount of generation depends on demand within the utility's service territory. The electricity is distributed to residential, commercial and industrial customers through a distribution network. The distribution function typically includes sales to ultimate customers. However, the distribution or "wires" function is separate from retail service, because retail competition is providing service to many customers.

2.1 Natural Monopoly and Utility Regulation

Electric utility regulation assumes that the industry is characterized as a sustainable natural monopoly. The electric utility industry has high fixed costs in the form of generating stations, transmission lines and a distribution system, but low variable costs per customer served. Within a service area, the larger the number of customers served the lower the average cost per customer.[7] In economic terms, a sustainable natural monopoly has a declining long-run average cost curve. If average costs decline with the size of a firm, a single large firm will have lower minimum average costs than numerous small firms. If the large firm is regulated to produce at minimum cost, and to sell its product at a reasonable return, customers derive benefits from the efficiency of large size. The rationale for the regulation of electric utilities is that customers obtain maximum benefits from a market with one large monopolist, but with regulated prices. Competition among smaller, high-cost firms produces higher prices to consumers.

The regulation of electricity companies began in the United States in the early 1900s. However, the economic analysis of natural monopoly goes back to at least the mid-1800s, where it was discussed by John Stuart Mill.[8] Electricity is generated, transferred between utilities, and distributed to customers subject to regulation by state utility commissions, and by the Federal Energy Regulation Commission (FERC). State utility regulation has various names and

[7] While this statement is apparently true in general, it is more correct where the capital stock is given. Natural monopoly is less apparent when implying that a doubling of the size of the utility's capital stock would reduce average cost per customer. For instance, economies of scale in distribution result from customer density. That is, large service territories do not necessarily have lower costs than small service territories.

[8] John Stuart Mill, *Principles of Political Economy*, 1848.

descriptions, and is referred to here as cost-of-service (COS) regulation. State utility commissions regulate intrastate utility business, such as generation and distribution. FERC regulates interstate energy transactions, including wholesale power transactions on transmission lines. The restructuring of electricity markets involves FERC at the wholesale level and the state PUCs and legislatures at the retail level, in some instances jurisdiction is unsettled.

The State Utility Commissions regulate retail rates, and typically approve rates to reflect the average cost of service.[9] However, as of December 2002, 24 states have passed legislation that opens their retail markets to competition. In 17 of these states customers can choose their electricity provider. These states include the PJM states of Pennsylvania, Maryland and New Jersey.

Historically, the natural monopoly contention applied to all utility services: generation, transmission and distribution. However, technical evidence was never one-sided with respect to generation. One interpretation of natural monopoly is that the utility as an entity was a natural monopolist. Another interpretation is that generation plants were characterized by economies of scale, which meant that average costs of generation decline with increasing size of the generating unit.[10] Throughout most of the first half of the twentieth century, newly constructed generating units tended to be larger than earlier units. The costs of generation declined on average from the early 1900s until about the mid-1960s. These declining costs are consistent with economies of scale in power plants. During the 1900s, significant technical improvements in power plants reduced costs and improved performance. Declining costs could also be attributed to technical improvements, rather than to economies of scale.

The long-term trend in declining electricity prices came to an end in the mid-1960s and reversed during the 1970s. Inflation and high interest rates penalized construction during the 1960s. Rising fuel prices penalized the electricity sector during the 1970s. Nuclear power plants experienced numerous difficulties that increased costs during late 1960s and the 1970s.

The historical experience indicates that the generation sector is not characterized by natural monopoly. Whether this segment of the industry was ever a natural monopoly is a matter for economic historians. However, there is now agreement that the generation market is potentially a competitive market. The restructuring of this market to encourage competition should reduce costs to ultimate customers and add economic value overall. Further, retail service can be considered separate from the "wires" or distribution function in that retail service is potentially competitive.

2.2 The Case for Natural Monopoly Unravels

Support for traditional utility regulation diminished significantly as a result of the increasing electricity prices during the 1970s. Further, a large technical literature cast serious doubt on the

[9] Actually utilities incur costs in providing electricity and utility commissions rule on whether costs are prudently incurred, which includes the allowed rate of return on investment. When the allowed rate of return covers the cost of capital, rates will cover the average cost of service.

[10] With the advent of distributed energy, or in other words, power generated at or near a customer's site, this assumption is being turned on its head. Smaller, modular generators of electricity and other technologies which enhance the efficiency of the grid are becoming more important and cheaper. This trend is in line with other decentralizing trends due to the advent of the Internet and other communications technologies.

alleged natural monopoly in the generation sector and further suggests the feasibility of retail competition. An additional economic literature on regulation indicated that the U.S. economy was over-regulated. George Stigler and others showed that regulation was typically sought by industry to protect itself from competition.[11] The deregulation of airlines, trucking railroads and banking produced declines in real costs from 25 percent up to 80 percent.[12] Several U.S. industries, such as the airlines and security brokerage produced large benefits to customers. The development of public choice theory explains utility regulation as interest groups maximizing their self interest rather than maximizing consumer interest. Each of these developments implies that restructuring electric utilities in a more competitive direction would provide benefits to customers.

There is evidence that the initial motivation for the regulation of electric utilities is more consistent with public choice than with natural monopoly. As explained by Hirsh, when utility regulation first evolved in the early 1900s, utility managers were able to persuade utility commissioners that electricity companies were much like telephone service and should be subject to regulation rather than to competition.[13] This example of industry seeking regulation to protect itself against competition is not unique, but is instead a general pattern. From the perspective of public choice, electricity regulation evolved as a result of well-organized interest groups using regulation rather than competition to protect their economic interests. Utility managers and stockholders comprise a more powerful interest group than rationally ignorant voters.

At present, states with relatively low electricity prices are averse to restructuring. Such low electricity prices are due to low (and sometimes subsidized) fuel costs, particularly coal and hydro power, and not to efficient regulation. The public choice perspective on utility regulation explains the incentive of such states to continue the regulatory path.

The electricity price increases beginning in the 1960s persuaded most observes that electric utilities were not natural monopolies. The failure of nuclear power to deliver electricity that was "too cheap to meter" added further evidence against the asserted efficiency of large scale power plants. Natural monopoly is a well-recognized market failure. However, by the 1970s, even casual observers of electricity markets understood that the generation sector was not characterized by natural monopoly.

Additional evidence refutes the natural monopoly contention. In 1975 Congress passed the Public Utility Regulatory Policy Act (PURPA) that encouraged the development of non-utility generators. This Act successfully encouraged the successful development of alternative sources of generation that were typically smaller than large scale generating plants favored by utilities. These so-called PURPA machines, or "merchant generators," owe much of their economic viability to government

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[11] George Stigler, "The Theory of Economic Regulation" *The Bell Journal of Economic and Management Science* Spring 1971, 2(1) pp. 1-21.

[12] Clifford Winston, "Industry Adjustment to Economic Deregulation" *Journal of Economic Perspectives*, Vol. 12, No. 3, Spring 1998, p 99.

[13] Robert F. Hirsh, "Regulation and Technology in the Electric Utility Industry: A Historical Analysis of Interdependence", in Jack High (ed.) *Regulation: Economic Theory and History*, Ann Arbor, University of Michigan Press, 1991, pp. 147-177.

regulation, but they nevertheless demonstrate an element of competitiveness with central power plants owned and managed by utilities.

Traditional cost-of-service regulation does not contain incentives to provide for the efficient supply of electricity.[14] The inefficient incentives include: insufficient incentive to minimize cost, insufficient incentive to innovate, inefficient allocation of risk, inefficient capital investment decisions, and insufficient incentive to use price-demand response in wholesale or retail markets. With revenues being tied to costs, there is little incentive to innovate and to introduce new technologies to reduce cost. In many states, PUCs approve fuel adjustment clauses that allow fuel prices to be passed forward to customers. In competitive markets the incentive is to switch from high cost fuels to lower cost fuels and to conserve energy, rather than to pass costs forward. As a result of such regulatory inefficiencies, markets subject to traditional utility regulation do not maximize value to ultimate customers.

A widely held view is that conventional COS regulation distorts investment choices in favor of large-scale and capital intensive projects. The well-known Averch-Johnson (A-J) effect argues that utility investments tend to favor large, capital-intensive investments. Traditional utility regulation grants utilities a rate of return on their capital investments, but allows utilities only a cost reimbursement on variable costs such as labor and fuel. Where the allowed rate of return exceeds the cost of capital, utilities are rewarded for large-scale capital intensive technologies. However, if the PUC allows a rate of return below the cost-of-capital then the utility will substitute other inputs for capital. The A-J effect is subject to some dispute in the technical literature. However, when utilities are allowed a rate of return for costs that are prudently incurred, utilities will prudently incur such costs.

Cost-of-service (COS) regulation contains insufficient incentives to innovate. A successful innovation may reduce cost, but utilities are reimbursed for cost even if they do not innovate. In traditional COS regulation, electricity demand is met by almost exclusively by central station power plants. A competitive market encourages innovation, such as distributed generation, energy conservation investments, and other consumer services and products. Regulated firms have an insufficient incentive to minimize costs. Where costs can be passed through to ratepayers, the incentives to minimize costs are not as strong as in a competitive market.

COS regulation can produce an inefficient allocation of risk. A basic principle of COS regulation is that utilities costs that are judged “prudently incurred” by state utility commissions should be allowed in the rate base and reflected in the price of electricity. An investment that is judged prudent by utility commissioners may turn out to be of high value or of low value. Some risk of this investment is shifted to ratepayers via the prudence review. That is, utility investments judged as prudently incurred, may subsequently earn an allowed rate of return regardless of their actual economic value. In the case of highly successful investments, utilities may receive no reward for risk bearing other than the minimal cost-of-capital. In competitive markets, investment risks are incurred by those who invest the funds. This allocation of risk provides an incentive to minimize cost and to innovate.

[14] Paul L. Joskow and Richard Schmalensee, *Markets for Power***,** Cambridge, The MIT Press, 1985, p. 5

The inefficient allocation of investment risk under COS is not an academic quibble, but has seriously and adversely affected ratepayers. Nuclear power entered the commercial electricity market only because numerous risks were shifted away from ratepayers. The first few commercial nuclear plants were "turnkeys" which meant that most risks remained with the venders. The Price-Anderson Act limited the liability of utilities in case of a serious nuclear accident. The risk of available storage for spent fuel was assumed by the government, and initial expectations are not yet realized.

However, the risks of nuclear power were not totally shifted from utilities. Some investments in nuclear power plants produced a rate shock, intolerable to consumers and commissioners. For the most part, investment costs are passed forward to customers via in traditional utility regulation. Investment risks – save a few nuclear power plants — are also passed through to customers. This inefficient allocation of risk is an inherent consequence of regulation.

This discussion emphasizes some negative aspects of electricity utility regulation because these characteristics provide evidence for suggesting benefits from restructuring. However, we should also recognize that electricity prices to ultimate customers declined continuously from the early 1900s through about the late 1960s. The efficiency and productivity of central station power plants continuously improved during this period and the resulting benefits were passed forward to customers. The long run decline in electricity prices in the U.S. contributed to productivity and hence economic growth in the U.S. economy, just as increasing energy prices in the 1970s reduced productivity.[15]

2.4 Summary

The long-term history of electric utility generation suggests the absence of an inherent natural monopoly. The generation market is not characterized by inherent market failures, natural monopoly or otherwise. The implication is that a competitive generation sector will provide greater economic benefits that a regulated generation sector. This implication is crucial for any state considering the development of a competitive generation market, and is restated. This brief review suggests an important lesson: **The restructuring of electric utilities in a more competitive can provide net benefits to consumers and additional economic benefits to a state.**

Net benefits from restructuring should result from the profit incentive to minimize cost, from the more efficient allocation of risk, from the incentive to innovate, from markets with a price-demand response, and from retail markets where suppliers compete by offering customers either lower prices or preferred bundles of services.

The initial impetus for electric utility regulation may be, as described by Hirsh, the efforts by electric power companies to use regulation to seek regulation for protection against competition. This public choice, or interest group, interpretation of regulation may also be an important factor in current electric utility restructuring and in its opposition.

[15] Dale Jorgenson. "Energy Prices and Productivity Growth" pp. 133-153, in Sam H. Schurr, Sidney Sonenblum and David O. Wood, *Energy, Productivity, and Economic Growth,*Oelgeschlageer, Gunn & Hain Pub. Cambridge, Mass., 1983.

3. Restructuring an Electricity Market: The PJM Region

This section provides a brief description of the PJM power pool. One purpose is to explain how the restructured PJM power pool market operates relative to the cost-of-service (COS) regulated market of investor-owned utilities. The restructured PJM wholesale market contains an incentive to minimize costs. This section presents some indicators that costs are reduced relative to a market where such costs are judged prudently incurred.

3.1 The PJM Regional Power Pool

The electric utilities in Pennsylvania, New Jersey and Maryland were organized into a power pool in 1927, which is the oldest and largest power pool in the United States.[16] Subsequently Delaware and the District of Columbia joined the PJM power pool. The PJM power pool now operates in the three PJM states plus Delaware and the District of Columbia and also in West Virginia, Virginia and Ohio.

Since its inception, the power pool was operated by the utilities within the pool. The power pool consists of a network of transmission lines that connect generating stations to power distributors. The goal of the pool was to enhance the reliability of providing electricity service. When a utility experienced a capacity shortage, the utility could arrange for a bulk power trade with other utilities within the pool.

As a result of federal legislation and regulatory actions, the PJM transmission network evolved from a system intended to enhance reliability with bulk power trades, to a system that supported a market with numerous buyers and sellers. Federal legislation such as the Public Utility Regulatory Policy Act (PURPA) encouraged the development and use of non-utility small power plants. The Energy Policy Act of 1992 authorized individual utilities to access the interstate transmission system.

For at least the last two decades, FERC has initiated Orders with the intention of increasing competition in interstate energy markets to improve their efficiency. FERC Orders 888 and 889 in 1996 required the open access to interstate transmission lines to power suppliers and purchasers. Order No. 888 also approved the creation of an independent system operator (ISO) in the PJM region and in other regions, where the ISO would operate wholesale and transmission markets within their region. In 1999, FERC issued Order No. 2000 that encouraged investor owned utilities, in the PJM region and other regions, to place control of their transmission systems in a regional transmission organization (RTO).

The PJM power pool is now managed by the PJM Interconnection LLC, which is a limited liability non-profit company. In the PJM power pool, the utilities in the region continue to own transmission, distribution and some generating assets, but form a "common market" within the region. A power pool effectively integrates the generation and transmission network into a common entity under the control of the ISO. The ISO behaves somewhat like a single utility by

[16] R. G. Rincliffe, "Planning and Operation of a Large Power Pool" *IEEE Spectrum,* January 1967, pp. 91-96.

dispatching power plants in their merit order and controlling the transmission system to ensure that power is received where it is needed. However, the ISO dispatches power over a wide region and on the basis of prices determined in an auction market.

A significant feature in understanding restructuring is that the wholesale market is guided by FERC and the ISO, while the retail market is guided by state legislators and PUC's. Indeed, references to the PJM market imply a wholesale market, not retail markets. The PJM Interconnection operates the wholesale markets of generation and transmission within a region. The market that serves ultimate customers is also being restructured to encourage competition in providing retail service. This restructuring is unique to each state and is provided by the state utility commissions with legislative approval. We use the term "PJM market" to refer to the wholesale regional market. Retail competition describes individual state efforts.

The electric utilities in the PJM region have not only relinquished control over their generating assets, several have relinquished much of the ownership, and have thereby become vertically unbundled. From 1999 through 2001 the generation by total electric utilities in the PJM region declined drastically and was replaced by generation by non-utilities.[17]

3.2 The PJM Energy and Capacity Markets

The PJM Interconnection manages energy and capacity markets, as well as ancillary markets that together provide wholesale electricity. The PJM Interconnection operates a real time (spot) market for energy, a day-ahead energy market, and various capacity markets. Electricity is supplied in a real time auction market, where the marginal cost of the last bid determines market prices received by all generating plants.[18] Electricity is also supplied with bilateral contracts. The real time and day ahead markets appear sufficiently robust so that bilateral contract terms can be referenced to real time markets.[19]

Participants in the PJM energy market have several choices. Energy purchasers can use the spot market or day ahead market, they can self generate, or they can purchase under bilateral contracts. The terms of bilateral contracts are agreed to by buyers and sellers and may include any duration and price term. Similarly sellers of energy may sell under contract as well as on the spot markets.

In the PJM power pool, the demand for energy is estimated and an auction market is used to meet load requirements at minimum costs. The network operator obtains bids for energy and for

[17] Edison Electric Institute, *Statistical Yearbook of the Electric Utility*, 2002, Washington DC. Table 3.6, p. 28. Generation in GW hours from 1999 to 2001, by state is: NJ, 38,868 to 1,630; PA, 161596 to 27,719; MD 49,324 to 88.

[18] Some critics of restructuring contend that when market prices are determined by the marginal cost of peaking units, baseload plants receive higher prices than with COS regulation; consequently, customers pay higher prices for electricity. This point may be applicable to many customers of Allegheny Power Co.

[19] The PJM market includes a reasonably efficient spot market that reveals current prices, a forward market for future product delivery, but no futures market that reveals expected spot prices in the future. A futures market or a swap market may provide the useful function of price-risk management. CAEM has done interesting work in this area which can be accessed by contacting Jamie Wimberly, CAEM President, at jwimberly@caem.org

capacity that trace out a supply curve, which is the industry marginal cost curve. The estimated load is the demand curve that is met regardless of price. The demand curve determines total load at any time. The supply curve determines the marginal cost price, which is then paid to each successful bidder.

Demand and supply for electricity are balanced continuously, and an auction "regulation" market is used for micro adjustments. In addition, a small amount of "spinning reserve" is maintained to meet short run increases in load and is relied on for reliability purposes during peak periods of demand. The PJM Interconnection operates regulation and spinning reserve markets in addition to other ancillary services.

Table 1 shows the market rates for various services provided by power plants as a function of the marginal cost of the power plant. Table 1 and some subsequent figures are electronic copies obtained directly from the PJM Interchange, and used in the PJM 2002 State of the Market Report.[20] As the marginal cost of the unit increases, the unit is less competitive during

Table 1.
PJM Revenues from Energy Capacity and other Services by Marginal Cost

Table 2-6
Net Revenues in 2002 by Marginal Cost of Unit
(Energy, capacity, ancillary service, operating reserve and total net revenues in $/MW -year)

Unit Marginal Cost ($/MWh)	Net Revenue Sources ($/MW-year)		Ancillary Services	Operating Reserves	Total Net Revenues: 2002
	Energy	Capacity			
$10	$161,427	$11,601	$2,822	$2,875	$178,726
$20	$90,015	$11,601	$2,822	$2,875	$107,314
$30	$54,536	$11,601	$2,822	$2,875	$71,834
$40	$33,258	$11,601	$2,822	$2,875	$50,557
$50	$20,781	$11,601	$2,822	$2,875	$38,080
$60	$13,767	$11,601	$2,822	$2,875	$31,066
$80	$6,959	$11,601	$2,822	$2,875	$24,258
$100	$4,318	$11,601	$2,822	$2,875	$21,616
$120	$3,219	$11,601	$2,822	$2,875	$20,518
$140	$2,628	$11,601	$2,822	$2,875	$19,927

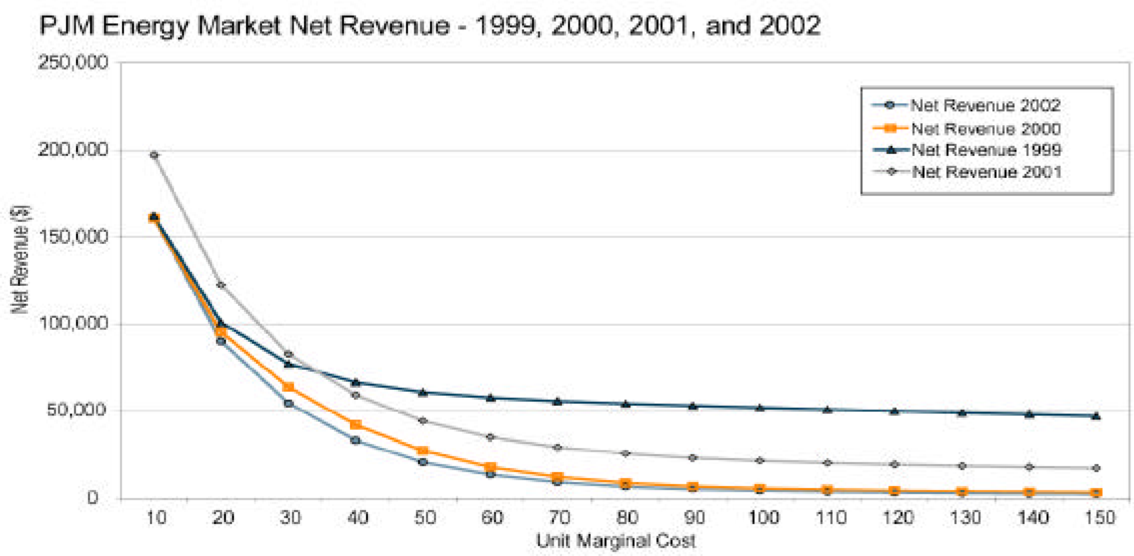
a larger number of hours and operates fewer hours during the year. The plant therefore earns less revenue selling energy. The point is that plants with low marginal costs have the largest net revenue.

[20] Table 1 and the following figures 1, 2 and 3 were graciously provided by Joe Bowring of PJM.

In the PJM market, plants receive revenue for energy, capacity and for other services. Generators receive a capacity payment for being on line and available. In 2002 installed capacity resources received $33.40 per MW-day, or $11,601 per year. Ancillary services include spinning reserves plus payments for “regulation”, where the regulation market provides very short run balancing between load and resources. In 2002, ancillary services earned $2,822 /MW-year. Operating payments were about $2,900 per MW-year of installed capacity. The last column in Table 1 shows total net revenue for generating plants with various marginal costs. The price of these ancillary serves is determined in an auction type market; hence we can reasonably expect that costs are minimized. Table 1 shows the various revenue sources for a generating plant during year 2002, but does not indicate how revenues or costs have changed during the last few years.

Figure 1 shows that net revenues received by generators have declined during the last four years. From the perspective of power producers, this figure depicts their revenue decreases. From the perspective of ultimate customers and assessing PJM’s restructuring effort, these cost decreases indicate the benefit anticipated from developing a competitive market. The incentive inherent in an auction market is to minimize cost. Figure 1 indicates that unit marginal costs are declining over time, as expected.

Figure 1.
PJM Energy Market Revenue by Year



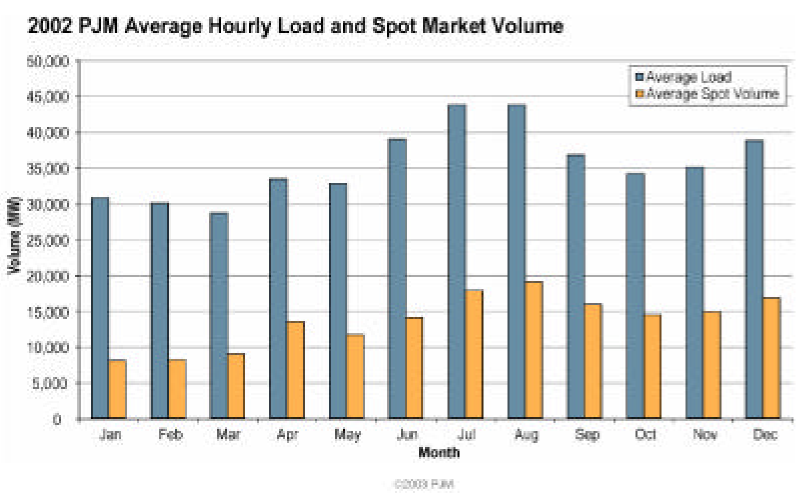
The spot market for energy, including the day ahead market provides a significant share of total energy needs in the PJM region. Figure 2 shows the average hourly load in the PJM region by month during 2002. The figure shows that spot market volume averaged 15,094 MW during the peak months and 12,259 MW during off-peaks, or 38 percent of average load during all hours. This spot market volume is an aggregate of real time and day ahead trading.[21]

Figure 2 also depicts the seasonal variation in average hourly load. During the two peak summer months, almost 45,000 MW is required, which is about 50 percent greater than load during the off peak months. These monthly data actually show considerable load smoothing. The daily peak load during summer months is much larger than off peak base load demand.

Although capacity and energy markets include spot and bilateral contracts, a reasonable expectation is that contract prices are frequently referenced to the spot market. Electricity suppliers can sell at spot, and hence are averse to selling at below spot. Electricity buyers can buy at spot, and hence are averse to buying at above spot. The real time and day ahead markets perform the function of price discovery, consistent with other spot markets. When a market price exists, contract trades are often referenced to that price.

Figure 2.
PJM Hourly Load and Spot Market Volume

pjm



The development of these spot markets is a significant accomplishment for PJM, and inevitably produces large benefits. Under COS, fuel was purchased under long-term fixed price contracts; investments were made under a long-term "regulatory bargain"; and electricity was sold to

[21] PJM Monitoring Market Unit, *2002 State of the Market*, PJM Interconnection, March 5, 2003.

customers with flat rate prices that were highly stable. In the auction market, the bids of only the least cost suppliers are selected; high cost producers have no contract protection. Spot prices send a clear signal to future generators to supply capacity, but only if they can do so at low competitive prices. The key incentive of the auction market is to provide energy at minimum cost rather than costs that are judged prudent by utility commissions.

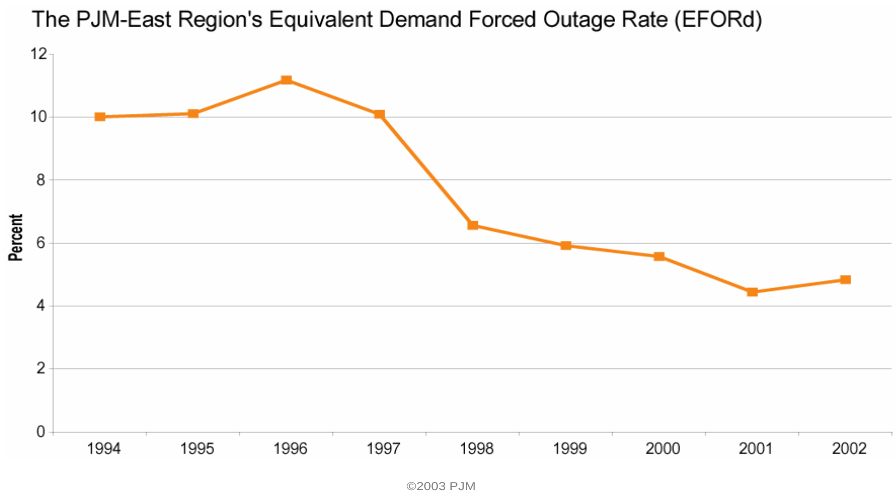
The auction market also sends a signal that encourages location efficiency. Location marginal cost pricing results in high prices, such as occasional price spikes, at specific locations that can influence the location decision of future generating capacity.

Another efficiency gain from the auction market is an increase in the capacity availability of existing power plants. The forced outage rate is a statistical measure of the probability that a plant will fail when needed. The lower the forced outage rate, the greater the reliability of the system, and the less the capacity required to maintain a reliable system. As depicted in Figure 3, the availability factor of installed capacity in the PJM-East Region has increased since the mid-1990s. The 2002 State of the Market Report shows that the forced outage rate of installed capacity in the PJM-East Region has tended downward since 1996.[22] From 1994 through 1997 the forced outage rate averaged about 10 percent. From 1997 to 2001 this rate decreased to about 4.5 percent.

The incentives inherent in the PJM wholesale market encourage reliability in capacity and penalize unreliability. The reduced forced outage rate and increased availability are expected efficiency improvements resulting from the design features of the restructured PJM market. These improvements are indicators of benefits, but do not directly measure benefit to ultimate customers. These efficiency improvements should reduce capital costs, which reduce wholesale prices that in turn reduce prices to customers. Hence changes in retail prices from 1997 to 2002 capture the effect of this reduction in forced outages, along with other effects.

Figure 3.
Forced Outage Rates Indicate Capacity Availability

[22] State of the Market Report 2002, p. 82



The capacity market is viewed here as consisting of two markets. One market determines the total amount of available capacity; while the other market determines the type and allocation of capacity among specific generators. The total amount of capacity is determined by estimates of peak load plus a reserve margin, as discussed in the last section of this report.

3.3 The Issue of Market Power in the PJM Region

The historical experience of regulating electric utilities suggests that reliance on market forces instead of COS regulation can provide for a more efficient supply of electricity and related services. However, doubts may arise when restructuring results in a small number of sellers providing energy and capacity. Market power, in and of itself, is a natural result of being in a less than perfectly competitive market (which is almost always the case) and is not necessarily of concern; however, market power abuse is using that power to increase market prices above competitive levels. Market power results when suppliers can set market prices, or, when such suppliers can withhold supply sufficiently to drive up prices. In auction markets, market power results in supply restrictions and price increases. The presence of market power in electricity and capacity supply markets contributes to occasional price spikes, which introduces uncertainty in affected markets.

The above paragraph provides a typical description of market power, but it neglects the demand side of the market. Market power is the ability to increase price above a competitive level. Supply restrictions provide pressure to increase price, but the actual price increase depends on the price elasticity of demand. Where there is no price-demand response, the demand curve is perfectly price inelastic (vertical). In this case, small supply restrictions cause large price increases. In the case of price sensitive demand, particularly a price elastic demand curve, a supply restriction may have little effect on market prices. Even where a small number of suppliers restricts supply, they have no incentive to do so because their revenues and profits decline. The PJM discussion of market power emphasizes the supply side. Indeed, as we see in section 6, the PJM assumption that the demand for reliability is price inelastic contributes to market power abuses.

The PJM view of market power is expressed in its State of the Market Report 2000. The Report begins by asserting four basic tests of competition: net revenue, price-cost markup, the HHI, and prices. Subsequent reports continue to provide evidence of these tests. HHI is the Herfendahl-Hirshman Index and is a measure of market concentration on the supply side.[23] A value of HHI of 1,000 or above indicates moderate concentration, and a value of 1800 or above indicates a highly concentrated industry. The various Interconnection Reports present numerous HHI estimates reflecting different markets, different time periods and other differences. Some HHI measures are above 1,800, several are above 1,500 and many are above 1,000. The results indicate that some markets have moderate or low concentration of suppliers, but a few markets are highly concentrated.

Concentrated generation markets contribute to auction market prices that occasionally exceed marginal cost. This effect is captured explicitly by PJM in its estimation of price-cost markup, which is the difference between price and marginal cost. Over a wide range, the price-cost markup numbers computed by the Interconnection show that most markets are reasonably competitive. The price-cost markup numbers are, of course, much higher during the occasional price spikes. The PJM Interconnection view of market power is that most markets are competitive most of the time, but market power is present on occasion and contributes to price spikes.

Since the early 1990s, the electric utility industry is displaying a trend towards consolidation through mergers. Investor-owned utilities (IOU) are merging with other IOU and with independent power producers (IPP). The Energy Information Administration (EIA) is documenting this merger and acquisition trend. The EIA notes that from 1992 through April 2000, 35 mergers or acquisition were completed between IOUs or between IOUs and IPPs.[24] As of year 2000, and additional 12 mergers were pending. The EIA notes that more recent mergers are also larger than earlier mergers, with 8 mergers completed during 1999 and 2000 having combined assets of $10 billion or more.[25]

The predictable effect of these mergers is to reduce the number of IOUs and their holding companies. According to the EIA, in 1992 there were 70 electric holding companies that held 78

[23] The HHI is calculated as the sum of squares of market shares of all firms in the market. HHI becomes large when a small number of firms have large market shares.
[24] Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, Washington DC, U. S. Department of Energy, DOE/EIA -0562 (2000) October 2000, p. 91.
[25] EIA, ibid. p. 91.

percent of the IOU generating capacity. By the end of 2000, the number of holding companies decreased to 53, but they held 86 percent of the electricity generating capacity.[26]

This consolidation of electric utilities increased the concentration of ownership of generating assets into a relatively few large utilities. According to the EIA, in 1992, the 10 largest utilities, ranked by generating capacity, owned 36 percent of the capacity.[27] By the end of 2000, the 10 largest companies held about 51 percent of this capacity. A similar trend towards increased concentration characterizes the 20 largest IOUs. A possible effect of the increased concentration of ownership of generating capacity is market power as an inherent market characteristic, given the absence of a robust price-demand response.

Price spikes may be hard to deal with by focusing on the supply side. The EIA analysis suggests the likely continuation of market concentration, although not necessarily within a given power pool region. However, the evidence is not one-sided. The PJM geographic market is expanding, which introduces more suppliers to the region. Imports and exports to the PJM region also contribute to a larger effective market. Each of these factors increases the number of supply options. Further, significant price spikes would occur during periods of extreme peak demand because of the need for power plants that are otherwise unused. The marginal cost for such capacity is naturally high, even in competitive conditions. The attenuation of price spikes is most effectively achieved by expanding supply choices and by increased ensuring the opportunity for price-demand response.

One view of the significance of market power comes from the University of California Energy Institute (UCEI).[28] Although the UCEI studies have a wide range, the Borenstein and Bushnell (directors of the UCEI) capture the bottom line from much of their work in asserting that short run benefits from restructuring are likely to be small, and long run benefits may be difficult to obtain.[29]

The reservations of Borenstein and Bushell about the benefits of competition result in large measure from the presence of market power among generators. Borenstein and Bushell emphasize that electricity cannot be stored, and further, in the short run quantity of electricity and generating capacity are highly insensitive to price at peak times. The inability to store electricity means that whatever is used at one instant must be generated at that instant, and therefore depends on the existing generating capacity, which is largely fixed in supply. An increase in electricity demand, with fixed and constrained capacity at peak use, can only result in large price increases, such as price spikes. The increased concentration of generating capacity only accentuates the presence of market power. According to Borenstein and Bushell, the presence of market power has made restructuring of electricity markets a much greater challenge than originally anticipated.

[26] EIA, ibid. P. 91.
[27] EIA, ibid. p. 97.
[28] Many of the reports from the UCEI can be obtained directly from their website www.ucie.org.
[29] Severin Borenstein and James Bushnell, "Electricity Restructuring: Deregulation or Reregulation?" R*egulation*, Vol. 23, No. 2, The Cato Institute, p. 46.

3.4 The Significance and Remedy For Market Power

Market power contributes to energy and capacity price spikes that occur on a few occasions throughout the year. One possible implication of these price spikes is a price risk that discourages market participation on the demand side. Another implication is the existence of monopoly profits. At issue is the significance of these consequences at present and the ability of the PJM region to reduce the problem in the future.

If market participants are highly risk averse, price spikes impose a risk that jeopardizes the integrity of the market. However, the available evidence indicates that the markets are sufficiently robust to encourage new investment in generation. Hence, price risk does not appear to discourage market participation. Buyers and sellers of electricity can diversify their portfolios and thereby reduce risk. For instance, purchases or sales conducted year around produce an average price where an occasional price spike has little overall effect. Buyers and sellers in the PJM region conduct much of their business with forward contracts that can be relatively immune from price spikes.

The amount of monopoly profits at present in the PJM region appears to be quite small, although Erin Mansur provides conflicting evidence.[30] Figure 4 depicts a PJM price duration curve reflecting only the top 5 percent of the hours of the real time market. The bottom 95 percent of the real time prices are relatively stable at about the 95th percentile level. The 95th percentile shows location marginal prices to average about $60/MWh, which is $60 per megawatt hour, or alternatively 6 cents per kilowatt hour. Peak prices increase by a factor of about 10 relative to average prices, although such increases occur much less than 1 percent of the time. Figure 4 also shows that the severity of price spikes was less in 2002 than during previous years.

The 2002 State of the Market Report reiterates the symptom and cause, just as in previous years. In a critique of the 2002 Report, PennFuture states: Each year the report emphasizes the need for better rules to prevent the manipulation of the capacity markets, but changes move at a pace that would make a tortoise fall asleep.[31] In a following paragraph, PennFuture emphasizes the need to implement demand response programs.

There is no evidence that the occasional price spikes result from suppliers “gaming” the system, or otherwise restricting production. Instead, it appears that price spikes result from, what economists call “scarcity rent” by owning a resource that has high transitory value, often due to location. PJM considers such price spikes an abuse and imposes price caps.

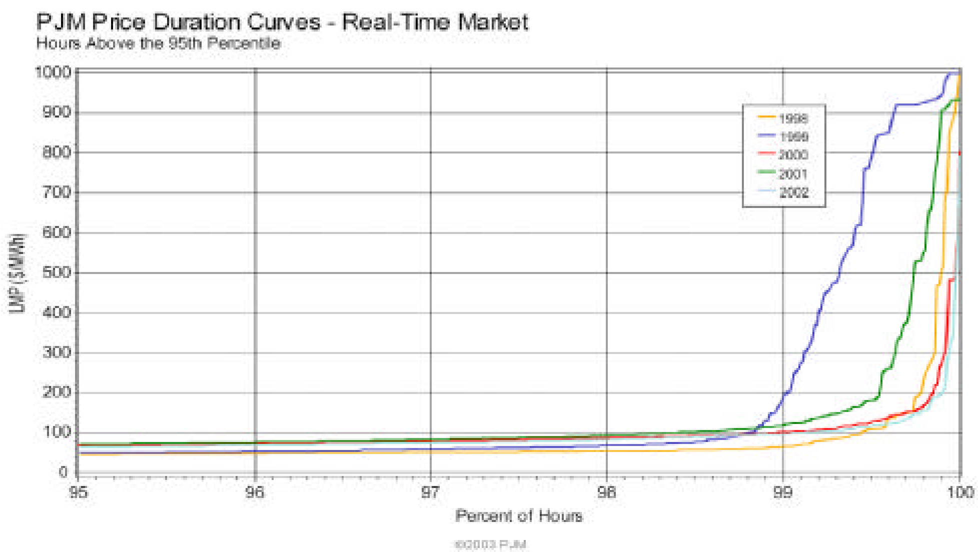
Another interpretation is that price spikes are a natural characteristic of a market in transition. Markets that function with textbook efficiency produce monopoly profits in the short run that are competed away in the long run. The location advantage of certain power plants contributes to

[30] Erin T. Mansur, *Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Market*, Power, University of California Energy Institute, April 2001, PWP-083, April 2001. Mansur estimates monopoly profits to be $224 during the summer of 1999.
[31] PennFututre “PJM Earns a B+” PennFuture Vol. 5, No. 5, obtained from www.pennfuture.org.

price spikes, but these price spikes also send a signal that influences the choice of future generating units.

As PJM recognizes, the mitigation of price spikes in the capacity market requires a price-demand response mechanism, where less capacity is demanded at higher prices. A price-demand response is required at the retail level. However, as explained in section 6, PJM could apply marginal analysis in the capacity market to determine the optimum level of capacity as well as an appropriate demand response to higher prices. Customers would demand less reliability at higher prices. Introducing price-demand response in the capacity market simply means reflecting customer interests consistent with an ordinary demand curve.

Figure 4
PJM Price-Duration Curve



4. Expected Benefits of Restructuring

Section 2 defines some inefficiencies characteristic of the traditional regulation of electric utilities. The natural monopoly view of generation is now almost universally discarded, which implies that competitive markets would improve efficiency relative to regulated markets. Further, the incentives characterizing COS regulation produce inefficient market outcomes. If restructured markets reduce regulatory inefficiencies, ultimate customers should obtain significant benefits.

This section describes a restructured electricity market, where competition produces maximum benefits to customers. By outlining a competitive market and comparing it to the PJM market, we can determine the progress PJM has made in achieving competitive results. The next section of this report provides an empirical estimate of the present value of benefits of PJM's current restructuring efforts. The analysis of competitive markets in this section suggests that PJM restructuring is currently achieving benefits and will achieve greater benefits from future market developments.

This report considers three markets that could be restructured with resulting efficiency improvements: the wholesale market, the retail market and the market for total capacity. This section first discusses the wholesale market and the potential benefits from restructuring. The pricing practice of most electric utilities is one of approximately flat rates, where such rates do not correspond to marginal cost. The next part of this section discusses the expected benefit of price-demand response pricing. Demand response is discussed separately because it relates to retail competition and to the market for total capacity. Some benefits from retail competition are then discussed. Retail competition in the PJM states at present is in transition and is characterized by the deals that define the transition period. The "deal" is discussed in section 4.4. The last part of this section reviews some of the impediments of achieving efficiency in a restructured market. The market for total capacity is discussed in the final section of this report.

In the PJM region, the wholesale market is defined by: a clearly specified competitive model, a firm commitment by the PJM Interchange to effectuate the model, FERC support of this model, and the absence of opposing interest groups. In the PJM states, the retail market is not characterized by an explicit competitive model, and these markets are in process of developing. At present, the wholesale market has developed in a highly competitive direction, but retail markets are developing more slowly.

Paul Joskow assesses the cost saving from restructuring to be small in the short run, but much larger in the long run.[32] Joskow's view is that most of the benefit from restructuring will occur over a very long time frame. Much of this benefit derives from the wholesale market where investments in new power plants provide electricity over subsequent decades. Existing power plants can be renovated to improve operating performance and reduce labor costs. These benefits

[32] Paul Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector" *Journal of Economic Perspectives,* Vol. 11, No. 3, summer, 1997, pp. 119-138.

are small relative to the efficiencies embodied in new investments, hence Joskow's emphasis on the long run.

The PJM power pool has operated for more than 70 years. With this experience and a commitment by the PJM Interchange, the PJM region is able to develop competitive markets quite quickly and obtain significant benefits.

A further implication of Joskow's view is that a major benefit of developing competitive generation markets is one that we will not see. Joskow notes that utility investments in generation and fixed price contracts would provide net losses to utilities of about $100 billion in an immediately deregulated market. These losses owe significantly to the uneconomic investments in nuclear plants. The estimated stranded costs are, from another perspective, estimated benefits to customers. The "cost" to utilities results from price declines due to competition that in turn provide commensurate benefit to customers.

In a competitive generation market, investors bear the risk of their own investments, and cannot shift the risks of "stranded costs" to ratepayers. However, many have accepted the case for stranded cost recovery due to either a belief that there was a "regulatory compact" to make utilities whole for those investments made in an earlier regulatory environment or simply as a matter of expediency as part of the trade off in a larger deal. A benefit of competition is that the risk of uneconomic investments will no longer be borne by ratepayers. The non-appearance of future stranded costs is a significant risk reduction benefit to customers; one that they will experience, but - probably and hopefully - not see.

PJM's official restructuring effort began in 1998 and is continuing to evolve over time. Although PJM has made a major effort to date, much of its restructuring changes are in the future. Joskow's view that the largest benefits are over the long-run, coupled with the PJM experience of only a few years, indicates that current estimated benefits are less than the potential long-run benefits of restructuring in the PJM region. Further, much of the expected benefit from restructuring is in the generation market. New investments require a several year period, but the resulting production occurs over subsequent decades.

A robust and reliable transmission system is essential to allow service providers to access customers. This condition derives from economics textbooks that state that a market with a large number of buyers and large number of sellers is required for a market to obtain competitive conditions. Transmission infrastructure provides the network that enables the interconnection and extension of markets, and thereby enables more buyers to have access to more sellers. The transmission system in the U.S. was designed primarily to facilitate bulk power trades, not to support integrated regional markets. The long run success of competitive restructuring efforts will require increasing use of an effective transmission network.

The present study focuses mostly on the generation and retail markets, and does not discuss transmission. However, we recognize the critical importance of an effective transmission system in connecting buyers and sellers. Subsequently, we note that shifts away from peak demand (load leveling) reduce capital requirements in transmission and distribution networks as well as generation requirements. Hence, the efficiency improvement resulting from the increased competition is the increased productivity of capital, including the transmission network. One benefit of a competitive generation market could be viewed as a diversity of efficient investment choices, along with minimizing costs of using the investment capital. This benefit would translate into lower average costs to customers from purchasing electricity. A diversity of choices should enhance the cost-effectiveness of obtaining reliability

4.1 Market Based Investment Decisions: The Wholesale Market

Although electricity flows in a continuous path of least resistance, the various electricity markets may be quite separate. In the PJM wholesale market, the supply side provides capacity and energy to the independent system operator (ISO), based on demand forecasts and power pool rules. On the demand side, the load serving entities (LSE) provide power to the utility, who distribute the power to ultimate customers.

The wholesale market provides the rules for investment decisions in generating capacity and the price received by this capacity, the amount of energy produced by type of capacity and the price paid for this energy. Most of these decisions are made in the PJM region under quite competitive conditions. The choice of capacity, such as fuel type and size of unit is made by the investors. The risks and return to investment are determined under a competitive process because both energy and capacity are sold into a competitive auction type of market.

The energy market contains the incentive to minimize the cost of producing energy. In this market, the auction price of the last amount of energy sold is the marginal cost, and this price is paid to all suppliers of energy. For each energy supplier, profits from supplying energy are the difference between market price and the marginal cost of supplying energy. Such profits provide the incentive to minimize cost. One benefit of PJM restructuring is the profits received by energy producers. When energy producers minimize cost, the marginal cost of providing energy is also reduced. In such a competitive market where MC determines the wholesale price (as opposed to average cost), ultimate customers benefit from competitively determined prices.

Each load serving entity is required to provide an amount of capacity based on expected peak demand and PJM operating rules. The price of this capacity is determined in an auction market, and hence is highly competitive. Capacity providers have an incentive to minimize cost because their profits are the difference between the market price and actual cost. Figure 3 above depicts a trend of increasing capacity availability per MW, which implies that capital costs per MW hour are declining. The incentive to minimize cost is likely producing the expected decline in costs.

The efficiencies produced by competition in the energy and capacity markets are passed through to customers in the form of minimum cost at a specified level of reserve. Both capacity cost and energy cost should be reduced by the competitive nature of these markets, compared with traditional COS regulation.

An indicator of the success of the PJM Interconnection in providing benefits to customers is the robustness of the wholesale spot markets for energy and capacity. When a market contains substantial variations in demand, a highly responsive spot market produces better value to customers than the rigidities of long term contracts or a vertically integrated generation and distribution market.

The benefit of competition in terms of risk allocation is not merely a theoretical curiosity. Under competition, highly risky investments — with huge downside risk are less likely to be undertaken.[33] If such investments are undertaken, stockholders and not customers bear the risk. During the 1990s, several estimates of the stranded costs of nuclear power plants and long term fixed price contracts appeared some were in the $100 billion area. Under competition, there are no stranded costs, at least those that are relevant to customers. An important benefit of a competitive generation sector is the avoidance of stranded costs. The estimates of stranded costs at least give us some idea of the size of inefficiencies of the past.

In sum, a competitive market for investment in generating capacity provides an incentive to select low cost but reliable capacity, and to build and operate this capacity at minimum cost. The benefit expected from competition includes reduced cost, real time prices and an efficient allocation of investment risk.

Although a competitive wholesale market provides net benefits to a region relative to a regulated market, the benefits are not distributed equally across customers. The auction market in the PJM power pool determines a regional wholesale price equal to the last successful bid, i.e., the marginal cost. Customers that paid high prices under regulation receive a significant wholesale price reduction benefit from competition. However, customers of low cost utilities may see rate increases in the near and medium term. Power plants that previously received a regulated rate of return now receive the regional marginal cost. In the PJM region, customers from certain utilities, such as Allegheny Power, will see higher retail default service rates as a result of these higher wholesale prices once the transition periods and capped rates expire. Wholesale competition produces a reduction and leveling of prices that provides net benefits to the region, but not equal benefits to all customers.

4.2 Price-Demand Response and Efficient Retail Pricing

The PJM model is a power pool with regional dispatch, but includes bilateral contracts and has a robust spot market and day ahead market. In the PJM region, an auction market determines wholesale prices in real time. The demand for electricity in the wholesale market is derived from the demand in the retail market. Demand variations in the retail market are passed through to the wholesale market, because there is little price-demand response in the retail market. The resulting demand variations in the wholesale market contribute to peak prices.

An ideal retail market would have a price-demand response that would moderate peak use and thereby moderate demand variations in the wholesale market. Efficient pricing of electricity at the retail level would produce at least three significant benefits.

1. A direct benefit to customers in the form of an increase in consumer surplus.
2. A reduction in required capacity

[33] Large risks also equate with the potential for large returns. Returns on merchant generation have been averaging 20 percent or more. This is important to note when answering the question of why more investment has not been flowing into new transmission capacity, with transmission investments characterized by regulatory uncertainty, prolonged legal challenges due to siting concerns and consistently lower returns closer to 10 percent, among other factors.

3. A decrease in price spikes in the wholesale market, and

Increase in Consumer Surplus

Real time pricing provides significant and direct benefits to customers. Those customers who prefer not to pay high peak prices would be able to shift or reduce their load and thereby reduce their energy costs. Customers with relatively flat load would no longer have to subsidize customers with large peak loads.

Not all customers benefit equally from efficient pricing. Customers with large peak loads would experience an increase in electricity costs, whereas customers with flatter loads would receive lower monthly bills. Peak demand occurs mostly during winter and mid summer months and results from a large demand for space heating and space cooling.

In the residential sector, high-income households are most likely to have large homes, and homes with central air conditioning. Low and middle-income households are more likely to have smaller and older residences with room air conditioners or even fans. Efficient pricing would increase the energy bills of many high-income households, while decreasing such bills to lower income households. At present, flat rate pricing discriminates against lower and middle income households because the high peak load costs of serving the air conditioning load are folded into the average rates paid by low income households. If the high cost of providing peak load for air conditioning were paid by its users, low and middle income households would see a decline in their bills.

Household energy expenditure data by the EIA confirms the highly regressive effects of energy costs. EIA household energy survey data shows that households with incomes in the range of $10,000 to $14,999 spend on average $1,051 dollars per year on energy.[34] Households with incomes of $75,000 or more spend an average $1,809 per year on energy. An increase in income by a factor of five results in a less than doubling of energy expenditures. A reduction in energy cost produces a much larger benefit for low income households, measured as a share of their income, than it does for high income households. The saving of electricity costs by low and moderate income households is a significant dividend from a successful restructuring effort.

Real time pricing would send an incentive to all customers to reduce or shift load away from periods of high cost use. Many customers may not respond to these price signals, but many would respond. Further, such prices are a signal to suppliers of technologies to market technologies that automatically shift load when prices reach some peak.

The adoption of real time retail pricing is highly controversial. Further, this controversy bears directly on the factors that determine the long run success of restructuring in benefits consumers. Economists naturally favor efficient pricing and assert significant benefits in the retail market, the wholesale market and in the market for total capacity. The PJM State of the Market Report recognizes the critical need for demand response, which means some approximation to efficient pricing.

[34] Energy Information Administration, *Household Energy Consumption and Expenditures 1993,* U.S. Department of Energy, Washington DC, DOE/EIA-0321(93), October 1995, p. 38.

Opposition to efficient prices comes from consumer groups and from those on the supply side of the industry that oppose the development of competitive markets. Consumer groups typically assert that low and middle income households prefer stable electricity prices and are highly averse to price risk. The alternative view – espoused here – is that low and middle income consumers would be better off with real time prices and the opportunity to select budget billing or other programs that reduce the effects of price risk. Certainly customers are better off with pricing choices than with regulated fixed rates that require large capital investments necessary to support flat rate prices.

Empirical evidence indicates that such households are not highly averse to energy price risks. Households that heat their homes with fuel oil are subject to the price risks of world oil prices. Heating oil dealers offer customers the opportunity to lock in winter fuel prices, and the dealers simply shed this risk on the futures market. However, only a small minority of heating oil customers choose to reduce fuel price risks, and instead simply buy at spot.

Actually, real time pricing would have a small effect, on average, on annual customer bills. Monthly bills during peak months could increase, but would decrease during transition season months. Prices would vary throughout each month, but much of these variations would cancel by the end of the month. Many electric utilities currently offer customers the opportunity to reduce the variation in their monthly bills by budget billing programs that average bills over a twelve month period. Again, we observe that only a small minority of customers actually participate in this risk reduction program. Customers could use such a program to reduce variations in monthly bills resulting from real time pricing.

Efficient real time pricing would offer low and middle income households the financial saving discussed above of not having to pay for peak air conditioning loads. Real time pricing also offers the opportunity to customers who would benefit from shifting load to do so and reduce their monthly bills.

Consumers who buy food, clothing, heating oil and gasoline in efficient markets and at spot prices with no ill affects, are unlikely to be adversely affected by purchasing electricity under the same conditions. Some consumers would benefit directly by efficient prices; all consumers would benefit indirectly by the reduced costs of supplying electricity from this demand response mechanism.

How do we explain the vocal opposition of consumer groups to efficient pricing, when consumers may be the largest beneficiary? Actually, we do not observe low income households complaining about the increased cost of running central air conditioners during peak periods. What we observe is termed the principal-agent problem. Residential customers will not benefit from restructuring, when their self-appointed agents recommend preserving price rigidities that reflect the self interest of the "thought leaders" instead of residential customers.

Reduction in Required Capacity

The pricing inefficiency resulting from flat rate pricing also affects the capital costs of providing electricity. Flat rate pricing results in the use of resources that are over-priced most of the time, and the use of resources that are under-priced during peak periods.[35] The result is under-utilized capital for base load generation, and over used peak load generation. Efficient pricing would reduce the need for peak use generating capability and thereby reduce capital costs of providing electricity. The shift of this load to base load generation would increase the productivity of this capital.

Another way to consider the inefficiency of flat rate pricing is that demand variations must be met by excess reserves. The demand for electricity shows enormous variations on a daily (diurnal) basis, on a seasonal basis, on an annual basis, and with large random weather related variations that are not readily predicted. All these random variations in retail load are passed through immediately to the wholesale market that must provide the power. Large increases in wholesale demand require an appropriate reserve margin to ensure reliable service. By relying on flat rates, variations in demand impose capital cost requirements for generation, transmission and distribution. A price-demand response mechanism at the retail level would moderate demand variations that would similarly moderate demand variations at the wholesale level. Price spikes at the wholesale level would be reduced. The need for capacity (per unit of kWh) would also be reduced.[36]

During periods of peak demand, the actual marginal cost of supplying power typically exceeds the flat rate price that consumers are paying.[37] With retail prices linked to average costs, consumers have insufficient incentive to reduce demand during these high cost periods. The cost of the kWh supplied exceeds the cost to consumers, resulting in the inefficient use of a scarce resource. Further, electric utilities incur a financial loss during such periods by selling power at below marginal cost. During off-peak periods the regulated flat rate exceeds marginal cost, resulting in an inefficient use of a large capital expenditure.

To the extent that customers reduce peak demand and load leveling is successful, average electricity rates should decline. Less generating capacity is required to meet peak demand and less transmission and distribution capital is also required.[38] The decline in transmission costs is from less congestion at peak periods, resulting in lower congestion costs. The reduction in all these capital costs per kWh would result in lower spot prices in the wholesale market, where such costs are recovered. With effective retail competition, these costs are passed forward to customers, causing retail prices to decline.

Reduction in Price Spikes

Restructuring efforts in the PJM region have been subject to price spikes in the wholesale market. During periods of peak demand most generating capacity is in use and unable to provide required

[35] Peak periods typically account for less than 50 hours per year and yet represent a disproportionate amount – by far -- of the total annual costs of electricity.

[36] The investment inefficiency resulting from flat rate prices is further documented in Severin Borenstein and Stephen Holland, *Investment Efficiency in Competitive Electricity Markets With and Without Time-Varying Retail Prices*, University of California Energy Institute, Center for the Study of Energy Markets, CSEM WP 106, November 2002.

[37] Case studies from Puget Sound and other utilities indicate that peak prices do not much exceed base load prices. The carrying cost of unused capital must, over time, increase its cost relative to capital that is more fully utilized.

[38] Bill Uhr, of UHR Technologies, illustrates that the distribution network experiences high costs to serve peak load. Bill Uhr, "Demand Response Pricing in a Regulated Utility" 22nd Annual Eastern Conference, May 22, 2003.

reserve margin. Price spikes are, in part, a result of thin reserve margins that characterize peak periods. However, the market for required reserves tends to exhibit price spikes above marginal cost, and the resulting "monopoly profits" result in higher costs to customers.[39] Achieving demand response to prices at the retail level would reverberate back to the wholesale market and moderate demand and price volatility. During periods of peak demand, spot prices encourage customers to reduce energy use, which in turn reduces the needs for wholesale energy and capacity.

4.3 Retail Competition with Product Differentiation

The potential benefits of competition in the wholesale market appear easy to identify, with reduced cost being the most obvious. In contrast, the potential benefits in the retail market are likely to be controversial. An obvious benefit of retail competition is reduced cost to customers. However, with efficient prices set in the wholesale market, it is questionable whether retail marketers can reduce cost. As retail competition develops during the restructuring transition, price competition is expected. As efficient markets develop, this competition is likely to develop into price-related competition for services.

The experience with deregulation in the telephone industry suggests the difficulty of defining benefits of retail competition. With the AT&T monopoly, telephones were black, had rotary dials, and telephone service had limited options. With deregulation, telephones were subject to significant innovations, and telephone service offers numerous new types of service. The current telephone service options were not anticipated prior to industry deregulation. Similarly, we can expect that retail competition will offer product differentiation, but there is little assurance as to what these differentiated products will be. Retail competition will be guided by the inherent market incentive to provide consumers with services that they are willing to pay for.

The likely potential benefits from retail competition are suggested by an analogy with the security brokerage industry. Prior to deregulation in this industry, brokerage firms provided a bundle of services that included expert financial advice and the actual transaction cost of a security trade. With deregulation, these services were unbundled, with transaction costs separated from other services. As a result, product differentiation in the industry occurred with a spectrum of prices and services. Investors can purchase securities through deep discount brokers (Ameritrade) at a negligible transaction cost. Investors can obtain some services and low transaction cost per trade through Charles Schwab. Investors still have the opportunity to trade securities through full service brokers, such as Merrill Lynch or Solomon Smith Barney. Competition between brokerage houses is intense, but these houses compete on the basis of services not on the basis of the market price of the security.

The deregulation of brokerage services with the resulting unbundling of services is providing enormous benefits to investors. The benefits are in the form of product differentiation of consumer services, and not in the form of reduced security prices. The successful deregulation of electricity

[39] As such, there have been a number of regulatory agencies, e.g., California and Ontario, to name a few, which have imposed price caps. Price caps, however, are exactly the wrong tool to use since pricing becomes even further distorted and price signals for new investment are lost.

markets should produce similar benefits to customers; much of this benefit is in the form of product differentiation of price-related services, not reduced prices for electrons.

In an effectively deregulated retail market, merchants would offer customers "differentiated product" which include a choice of various bundles of services. One such product is price-risk management. Another product is priority service.[40] Priority service refers to the reliability or quality of electricity. At present, most customers are provided the same uniform high reliability and quality. However, this uniform standard ignores significant differences between customers in terms of their uses and needs for electricity, and in their willingness to pay for reliable service.[41] All customers pay for highly reliability of service, whether they value it or whether they do not. Those placing less value on high reliability service subsidize those who place a higher value on reliable service. As noted by Munasinghe and Sanghvi, application of a single reliability standard reduces investment inefficiency over time.[42] The continuously declining prices of microchip technologies increase the feasibility of offering customers choices of reliability and power quality at corresponding marginal costs. Such choices would benefit at least some customers.[43]

The states with high electricity prices are most active in their restructuring efforts, with low cost states showing less enthusiasm. However, retail prices between states are primarily determined by indigenous resources (hydropower), fuel prices (especially coal), and stranded costs from nuclear power plants.[44] The factors that contribute to cost inequality between states do not indicate that competition would especially benefit high cost states. Further, prior to deregulation efforts, COS regulation was applied uniformly across states, and, with the exception of nuclear plants, has about equally inefficient outcomes across states.

The main beneficiaries of competition in electricity markets are customers (end users), but not necessarily those residing in high cost states. States with low cost electricity rates could be losers

[40] The term "product differentiation" is used by Chao et. al. and indicates that marketers compete on the basis of offering different bundles of goods and services and not merely on the basis of price. See Chao, Hung-po, Shmuel S. Oren, Stephen A. Smith, and Robert B. Wilson, "Priority Service: Market structure and Competition" *The Energy Journal, Special Issue On Electricity Reliability,* Vol. 9, 1988, pp. 77-104.

[41] The case for reliability pricing is developed by Bruce Humphrey, "Mixed Signals Cloud Reliability Picture" www.energypulse.com.

[42] Munasinghe, Mohan, A. Sanghvi, "Reliability of Electricity Supply, Outage Costs and Value of Service: An Overview," *The Energy Journal, Special Issue on Electricity Reliability,* Vol. 9, 1988, p 7, where the result is obtained by C. K. Woo and N. Toyama, "Service Reliability and the Optimal Interruptible Rate Option in Residential Electricity Pricing," *The Energy Journal*, Vol. 7, No. 3, 1986, pp. 123-136, and Chao, Hung-po and R. Wilson, "Priority Service: Pricing Investment and Market Organization", *The American Economics Review*, Vol. 77, 1978, pp. 899-916.

[43] The practical implications of priority service are less apparent than its theoretical appeal, for one because reliability is mostly related to the distribution system. Further, it is unclear whether pricing for reliability adds value over and above the efficiency produced by real time pricing for energy.

[44] All of these factors cited could be viewed as artificial in that public policies have been implemented which subsidize certain fuel sources and investments, e.g., nuclear power. Some would argue that even indigenous factors, e.g., hydropower, are subsidized through the building, operation and maintenance of dams with federal funds. If these subsidies were to end due to budget cuts, privatization or for environmental reasons, then "low cost" states may be more receptive to restructuring arguments.

by not improving the efficiency of their markets, because they will lose a competitive advantage to states that reduce their electricity rates. The next section presents preliminary empirical evidence that the PJM restructuring states are closing the gap on electricity prices to non-restructuring states.

In sum, the expected benefits from retail competition may be from price competition during the transition phase of restructuring, but would evolve into competition based on product differentiation as ultimate customers see real time electricity prices. Markets would provide product differentiation, which means bundles of services specific to individual customers. One obvious service is price-risk management, for those customers who wished to avoid the risks inherent in real time prices. Another service is priority service, which means providing variations in the quality and reliability of service that customers prefer and are willing to pay for. Distributed generation is also encouraged by efficient pricing, because it is one way to reduce peak demand, or obtain low priority rates, and still maintain reliable service. Many of the various energy related services are, like telephones service, not readily apparent.

4.4 Retail Competition: Let's Make A Deal

Restructuring in the wholesale regional market is characterized by auction markets and real time prices. Restructuring in the state retail markets is characterized by open access to ultimate customers and negotiated deals between utility commissions and utilities that include transitions costs, stranded cost recovery, and negotiated temporary retail price declines.

Some of the customer cost reduction benefit of retail competition is being deferred to pay the transition costs of restructuring. The recovery of stranded costs by utilities delays the realization of benefits of restructuring by ultimate customers.[45] To illustrate, we simplify the analysis and note that the market value of a power plant is equal to the present value of its future net revenue. Under COS, future net revenue is determined by regulated rates to customers, and may be quite high. Under restructuring, such as the PJM auction market, the value of the power plant is still equal to the present value of future net revenues. However, the wholesale electricity price is now determined in an auction market, where participants are minimizing cost just to enter the merit order.

The market value of plants is likely to decline significantly, in lock step with the decline in wholesale auction market prices relative to regulated prices. This decline in wholesale prices represents a large potential benefit to customers. However, the decline in prices results in a similar loss to utilities termed stranded cost. The electric utilities in the PJM region and in other regions are recovering much of their stranded costs. At present, some benefits from restructuring are being delayed because they are returned to the utilities for stranded cost recovery. When stranded cost recovery is complete, benefits to customers will increase.[46]

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[45] As noted previously, it is not the intention of this report to revisit the stranded cost recovery debate. It is enough to state that stranded cost recovery was approved and generally accepted by most stakeholders as part of a larger deal in restructuring states for many reasons.

[46] A line from the movie "Quicksilver" is descriptive here: "The money is still there; it just belongs to someone else".

Pennsylvania, New Jersey and Maryland allow for significant recovery of stranded costs and other transition costs. In Maryland, the distribution utilities are given a fair opportunity to recover prudently incurred stranded costs. New Jersey also allows for distribution utilities to recover stranded costs.[47] Pennsylvania appears to be most generous with its stranded cost allowance, by allowing stranded costs to be fully recoverable, with recovery period up to 10 years.

Table 2 shows the allowable stranded cost recovery of stranded costs by utility in Pennsylvania. The recovery period varies from 7 to 10 years. Total allowable recovery (the sum of column 2) in Pennsylvania is $11,102 million. This allocation of the benefits from restructuring markets defers much of the benefit to customers to future years.

Paul Joskow also notes that stranded cost recovery largely redistributes the cost reductions of restructuring back to the utilities. Joskow states: "How retail prices could fall dramatically to reflect lower wholesale prices and utilities could recover their stranded costs …was a bit of questionable arithmetic that was largely glossed over."[48] More of the benefits from restructuring will be realized when the collection of stranded cost ends, and retail prices then decline. For example, preliminary evidence in the Duquesne service territory indicates that retail prices declined by 25.5% when stranded cost collection ended in 2003.[49]

Table 2
Transition/Stranded Costs in Pennsylvania

Company	Allowable Stranded Cost Recovery (in millions of $)	Length of Recovery (in years)
Duquesne Light	$950	Ended June 2003
GPU Energy (Met ED)	$866	11
GPU Energy (Penelec)	$386	11
PECO	$5,260	11
Penn. Power & Light	$2,970	10
Allegheny Power Co,	$670	10

Source: John Hanger and Peter Adels, "The Skinny on Caps and Stranded Costs" *Energy Pulse, http://www.energypulse.net August 7, 2003.* Note the sum of Col. 2 is $11,102 million. This source identified Allegheny Power as West Penn Power Co, with a 9 year recovery period, but officials from Allegheny indicated that West Penn is owned by Allegheny and that the recovery period is 10 years.

[47] Federal Trade Commission, *Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform: Focus on Retail Competition,* Washington DC, September 2001, p. A45 for Maryland and p. A77 for New Jersey.

[48] Paul Joskow "The Difficult Transition to Competitive Electricity Markets in the U.S." *AEI-Brookings Joint Center for Regulatory Studies*, July 2003. p. 6.

[49] John Hanger and Peter Adels "The Skinny on Caps and Stranded Costs" *Energy Pulse,* http:/www.energypulse.net , August 7, 2003.

The FTC report also presents data on the transition charges in terms of cents/kWh by electric utility. Some of these charges exceed 2 cents/kWh (Duquesne) and a few are less than 1 cent/kWh (West Penn), however an approximate average transition charge is about 1.5 cent/kWh per year throughout the recovery period. Using EIA data, the average price of electricity in Pennsylvania is 7.3 cents/kWh for year 2002. This average transition charge is therefore 20.5% of the total price of electricity. These data indicate the potential of large cost reduction benefits of restructuring, with these benefits being received by ultimate customers.

The state retail restructuring efforts are undertaken with an objective of not imposing risks of price increases on consumers, legislators and the PUCs. As part of the deal where utilities could recover stranded costs, the utilities were also required to reduce retail prices for a specified number of years. In Maryland, rates were capped for 4 years from 1999, and utilities were required to decrease their rates from 3 to 7.5 percent beginning June 30, 1999.[50] In New Jersey all customer classes received an initial 5 percent rate reduction from April 1997 rates, with an additional 5 percent reduction spread over 3 years. Pennsylvania did not require rate reductions, but the major utilities agreed to reductions up to 8 percent for the first year.

The decline in retail prices during the first few years of restructuring reflects negotiated prices rather than auction market prices. This fact does not affect customer benefits in the near term because such benefits result from the decline in prices, not from the source of the price change. The retail price declines are only feasible if there is sufficient cost saving in the wholesale market. However, it is crucial for customers that such cost saving be permanent and not transitory. This analysis estimates benefits to customers that would result if current electricity price declines from 1997 through 2002 are permanent.

5. A Modeling Analysis of Restructuring Benefits

This section first develops the economic framework for measuring the benefits of restructuring the PJM market in a more competitive direction. Benefits are measured according to the standard economic principles. The benefit measure of willingness to pay (WTP), or consumer surplus as it is often called, follows directly from basic economic principles, and is developed in the first part of this section. The second section explains the relationship between identified efficiency gains and the economic measure of benefits. The economic measure of benefits captures the composite effect of all individual efficiency gains.

The calculations of the economic benefits of restructuring in the PJM region are presented in the third part of this section. Benefits are estimated for current restructuring efforts, not future restructuring changes. However, benefits are expressed as the present value of the long term effects of current restructuring.

[50] The data in this paragraph is from the Federal Trade Commission report, *Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform*, in the respective state appendices.

5.1 Economic Benefits: Consumer Surplus and Industry Efficiency

Economic analysis provides a quantitative dollar measure of benefits that is particularly appropriate to measure the benefits of increased competition. The value of a changed market condition is the monetary value that participants place on the change, and it is measured as their willingness to pay. The willingness to pay measure of economic benefits is explained in economics textbooks, with Mankiw's principles book providing a good introduction.[51] More advanced treatise on cost-benefit analysis, such as E. J. Mishan, also explain the measurement of benefits in terms of consumer surplus and WTP.[52] A particularly important application of cost-benefit analysis is in environmental policy. The U.S. EPA explains the benefit of an environmental improvement as the net WTP for that improvement. Consumer surplus is appropriate for measuring the dollar benefits of reducing externality cost, or increasing environmental benefit.[53] The EIA also uses consumer surplus to define the benefits of optimum capacity reserve margins, as well as the benefits of real time pricing.[54] Each of these sources defines benefits to consumers as consumer surplus, which is net WTP. In addition to its technical correctness, WTP has a common sense appeal: the benefit that consumers receive from an improved market outcome is measured as their willingness to pay for that improved outcome.

The measure of economic benefits begins with a demand curve for a particular good. An aggregate electricity demand curve depicts the amount of electricity demanded during a given time period in kWh as a function of the price of electricity. An equivalent interpretation is that a demand curve shows the maximum price that consumers are willing to pay for each amount of electricity consumed. A hypothetical demand curve is depicted in Figure 5, which we imagine to reflect the annual demand for electricity in the PJM region.

The demand curve depicts that customers use more electricity as lower prices. At lower prices consumers conserve less electricity, and some customers may switch from other fuels to electricity. Each price along the electricity demand curve reflects its marginal value to customers and the maximum that customers are willing to pay for electricity. Figure 5 shows that at a price of electricity P_0 customers will consume Q_0 units of electricity (kWh/year). The total economic value of electricity is the monetary area under the customer's demand curve from the origin to Q_0. This area is termed total willingness to pay for electricity. Part of this total benefit is a rectangle (P_0Q_0) offset by customer costs, which equals the price of electricity times the quantity consumed.

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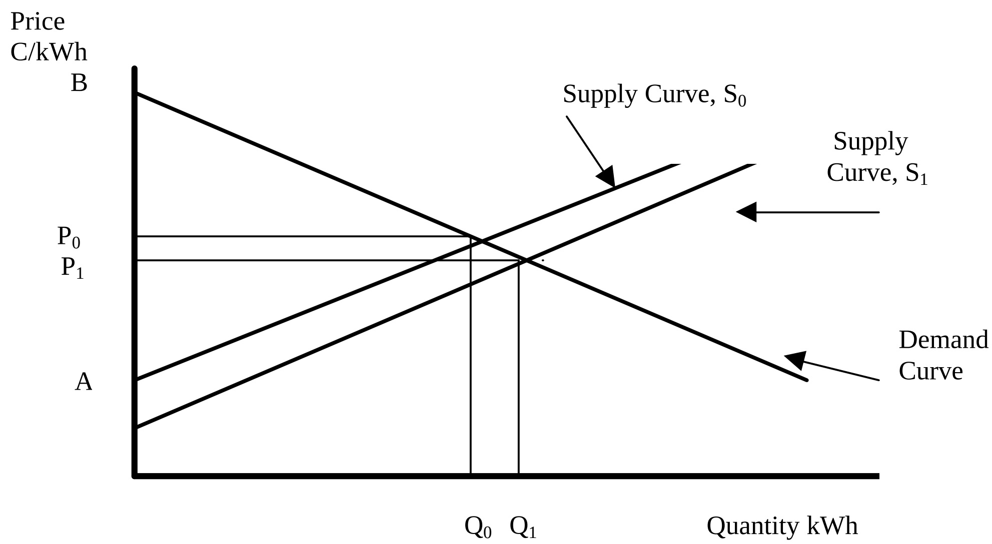
[51] N. Gregory Mankiw, *Principles of Economics*, Second Edition, Harcourt Brace Publishers, 2001 see especially Ch. 7.

[52] E. J. Mishan, *Cost-Benefit Analysis*, New York, Preager Publishers, 1976, especially pp. 24-39.

[53] U.S. Environmental Protection Agency, *Guidelines for Preparing Economic Analysis*, Washington DC, EPA 240-R-00-003. September, 2000, pp. 12.

[54] Energy Information Administration, *Electricity Prices in A Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, U.S. Department of Energy, DOE/EIA-0614, August 1997.

Figure 5.
Net Benefits From Restructuring
An Electricity Market



The other part of the monetary value of consuming electricity is the triangle area in Figure 5, which is the area under the demand curve but above market price. This area measures the net benefits to consumers from consuming electricity. This area represents the net willingness to pay for electricity. The high value of electricity results because it is a necessity in many household and business uses. Heating, lighting, running personal computers are high value activities that result in a corresponding high value for many electricity uses. Net willingness to pay is a total monetary value minus actual payments; it is also called "consumer surplus". The correct measurement of the benefits of restructuring to customers is their increment in consumer surplus resulting from restructuring.

The net benefits received by producers, termed producer surplus are comparable to the net benefits received by consumers. The electricity supply curve with COS regulation is denoted as S_0. The triangle, P_0Q_0A is a monetary measure of producer surplus. The net welfare of producing and consuming this level of electricity is the sum of producer and consumer surplus. The benefits of restructuring are estimated as the change in producer and consumer surplus, however the largest benefit is to consumers.

As a result of restructuring, the cost of supplying electricity declines, as reflected by the new supply curve S_1 in Figure 5. The new supply curve reflects the composite effect of all efficiency improvements in the wholesale market and in the retail market. Because WTP is a composite measure, the contribution of specific factors, such as retail competition and wholesale auction markets, cannot be separated from the total effect.

As suggested by Figure 5, restructuring should produce an increase in consumer surplus resulting from a reduced price of electricity. Given a demand curve for electricity, and a reduced price (from P_0 to P_1) resulting from competition, we can estimate the dollar benefits to consumers. We estimate the benefit of restructuring as the decline in retail electricity price (? P) times the quantity of electricity purchases that we simply denote as Q. In this approximation, ultimate customers benefit from restructuring as measured by their decline in electricity costs. [55]

An important interpretation of this model is the calculation of benefits to producers. In the short run, lower cost to customers means reduced revenue to producers, and much of the increase in consumer surplus comes at the expense of a corresponding reduction in surplus to producers. The net increment in economic benefit is the small triangle in Figure 5. Maloney and McCormick, in their estimation of benefits, deduct losses to electricity producers and measure net benefits as this triangle.[56]

The loss of producer surplus receives much attention in the electricity deregulation literature where it is referred to as stranded costs. The EIA presents several scenario estimates of stranded costs on a national level, many of which exceed $100 billion.[57] The EIA notes that estimates provided by other organizations typically exceed $100 billion. The $100 billion figure is an estimate of the loss of producer value (surplus plus cost) resulting from competition in the generation sector. However, stranded costs in the PJM region are largely recovered.

Although the benefits of restructuring are defined as the increment in producer plus consumer surplus, this analysis focuses on benefits to customers. The rationale for competition is that it achieves economic efficiency, which in turn maximizes benefits to consumers. In competitive markets, producers have every opportunity to earn profits, but large profits encourage new competitors to enter the market who compete these profits away over time. In competitive electricity markets, *some* investors in generation earn profits, and *some* retail marketers earn profits, but *all* customers should be better off. The consumer surplus measure of benefits reflects Adam Smith's notion of an invisible hand: suppliers act in their own self interest, which is to earn profits, but in doing so, provide maximum benefits to customers, which is consumer surplus. The empirical evidence on the benefits of deregulating industries in the U.S indicates that most of the cost saving accrues to consumers.[58]

Under COS regulation, utilities are allowed a rate of return, supposedly consistent with competitive markets. [59] Electricity suppliers therefore received some producer surplus under regulation. Electricity suppliers also receive producer surplus (stranded cost recovery) during the

[55] In Figure 4, the amount of electricity purchased is estimated as $(Q_0 + Q_1)/2$.

[56] Michael T. Maloney and Robert E. McCormick, *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Industry,* Volume 1, Washington DC, Citizens for a Sound Economy, 1996.

[57] Energy Information Administration, *Electricity Prices in A Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, U.S. Department of Energy, DOE/EIA-0614, August 1997, p. 61.

[58] Clifford Winston, "U.S. Industry Adjustment to Economic Deregulation" *Journal of Economic Perspectives,* Vol. 12, No. 3, Spring 1998, pp. 89-110.

[59] Usually 8 to 12 percent return calculated from the costs associated with providing service.

transition to a competitive market. Electricity suppliers also receive producer surplus in competitive markets. In this analysis, we assume that restructuring redistributes producer surplus from regulated utilities to competitive suppliers, but produces no net change. The increase in surplus accrues primarily to ultimate customers in the form of price decreases and is measured as ? PQ.

5.2 Benefits of Restructuring: The Common View

A working group, formed by the Center for the Advancement of Energy Markets, to advise this analysis, suggested some possible benefits from restructuring in the PJM region. These suggested benefits are discussed briefly. Most of these specific benefits of restructuring are captured in the benefit estimates presented, but estimation of some benefits is beyond the scope of this study.

1. The forced outage rate of plants has been cut by 50% and that reduction has avoided the need for approximately 1500 megawatts of new capacity.

The forced outage rate is discussed above and depicted in Figure 3. The forced outage rate in the PJM region has declined since 1997, indicating that capacity is available a larger share of the time. The implication is that less investment in capacity is required to obtain a given level of reserve margin. Wholesale prices should thereby decline. This efficiency improvement contributes to cost reduction benefits, but is not estimated as a separate factor. The measure of these benefits is captured in the consumer surplus that results from price reductions.

2. Competitive markets have led to approximately 8,000 megawatts of new capacity constructed between 2001 and 2003. All this was installed without any base rate increases, unthinkable under the old system.

This addition of installed capacity is a striking testimony to the success of the PJM restructuring effort. When such investment occurs in a market with real time spot prices, rather than long term contracts, it confirms that such a market is highly efficient. The restructured PJM market provides investment incentives without the regulatory bargain of allowing costs to enter the rate base, or without long-term fixed-price contracts. This investment is indicative of a robust and well-functioning market established by the PJM Interconnection.

The benefit of these investments, as monetary value to customers, will accrue over the next couple of decades in the form of an increased supply of electricity at reduced prices. The new installed capacity will affect the supply of energy and capacity and thereby affect market prices. The future benefits of these investments are not captured in this analysis, because we are only measuring the economic value of price reductions currently in place. However, we emphasize that long-run benefits are likely to increase and these capacity investments are just one source of future value.

3. Record summer peaks have been reliably met in 1999, 2001, and 2002.

A significant challenge in a restructured market is simply to meet demand and maintain reliability. Under COS regulation, utilities were able to maintain reliability and to meet peak demand. However, the costs of this reliability during peak periods was high because flat rates did not encourage a demand response and instead required high capacity reserve margins. Maintaining reliable service during high peak periods indicates that the PJM system is well-functioning system, which is indeed an accomplishment. However, meeting demand is not a net benefit, because it would have been met under COS regulation. A benefit to customers results if this demand is met at a lower cost, reflected in lower rates to customers. This benefit is captured in the estimate of consumer surplus.

4. The expansion of PJM and other factors has allowed a substantial decrease in the reserve margin required to maintain reliability.

A successful restructuring effort should provide significant benefits to customers by reducing the capital costs required to meet demand. A decrease in reserve margin can contribute significantly to reducing capital costs, and hence rates to ultimate customers. Figure 3 above shows the increase in available capacity and suggests that capital costs per kWh of generation should decline. This decline in costs should translate into an increment in consumer surplus.

5. Fuel diversity has increased with natural gas joining coal and nuclear as major sources. The new plants are nearly twice as efficient as the old plants. This reduces emissions per kilowatt-hour. Plus gas is a cleaner burning fuel than coal.

Increasing fuel diversity reduces various risks. Each technology that generates electricity has some type of risk. Hence there are risks in relying on one or two fuels; these risks are diversified away by using a portfolio of fuels. The fuel diversification benefit is not captured here, except to the extent that it may also affect the change in average prices. The benefits of price declines are captured here, but the risk reduction and environmental benefits are not captured in this study.

6. Wind energy has been introduced and will likely reach 250 megawatts of installed capacity by the first quarter of 2004. It is highly likely that PJM will have 1,000 megawatts of wind installed within 5 years.

Wind energy has strong emotional appeal, both to proponents and to opponents. Wind energy offers three potential benefits: an environmental benefit, a risk reduction diversification benefit, and a cost reduction benefit. The environmental and risk reduction benefits are not quantified in this study. To the extent that wind energy, or other fuels, offers these benefits, this study understates total benefits. However, if wind energy reduces cost, this benefit will be captured.

7. In Pennsylvania, 2600 megawatts of load is being supplied by competitive retailers. Competitive retailers also have meaningful market shares in PEPCO service territory.

According to a Federal Trade Commission report, in April 1999, 6.8% of residential customers in Pennsylvania were served by an alternative supplier, but in July 2001, this percent increased to

7.3%. The increase in alternative retail providers indicates successful restructuring, but is not a measure of benefits.[60] The benefit from these alternative providers is either the reduced prices to customers, or, price related services. The benefit of reduced prices is estimated here. The benefit from preferred bundles of services is captured here only in a qualitative sense.

8. Wholesale spot market prices and 1 year forward contracts have normally been well below what monopoly customers were paying for generation back in 1996. It is critical to compare the generation portion of the old monopoly rate (and that includes the stranded cost as the stranded cost represents the uneconomic generation investment) to competitive wholesale and retail rates.

Very true: the success of the PJM restructuring effort is likely to be mostly in the wholesale market and is measured by a reduction in wholesale prices relative to monopoly rates.

9. In some parts of PJM, Green Mountain and PEPCO are offering 100% renewable retail products today that are below what customers were being paid for coal/nuke generation in 1996 (see `www.cleanyourair.org`).

The diversification and environmental benefit of renewable energy is discussed above. The reduction in rates is captured here in estimates of consumer surplus.

10. Other benefits include the beginning of demand response, though DR has been too slow to evolve due to regulatory timidity.

Very true: a successful price-demand response program would: (1) add directly to consumer surplus, (2) would reduce required reserves and would thereby lower customer rates, and (3) would reduce price spikes in both energy and capacity markets. Unfortunately for PJM customers, demand response has been too slow to provide customers with the potential benefits that restructuring could bring.

Some of the benefits listed here, such as environmental quality and fuel diversification are beyond the scope of this study. More typically though, the suggested benefits are indicators of benefits, or factors that contribute to benefits. The improvement in economic well-being of ultimate customers in the PJM region from restructuring is reflected in their increment in consumer surplus. Several of the factors mentioned above should reduce cost and are thereby captured in estimates of consumer surplus.

In sum, the consumer surplus, or WTP measure of benefits used here reflects the composite effect of efficiency improvements in one monetary sum. This measure of benefits does not capture all benefits, e.g., risk reduction and environmental benefits, but does capture most of the monetary benefits of restructuring.

[60] If marketers capture a significant market share, they are probably producing large benefits to customers. However, if marketers exit the market, it could indicate a regulatory failure (price caps) and reduced benefits, or, increased efficiency by the local utility with increased customer benefit.

5.3 Calculating the Benefits of Restructuring the PJM Market

This section presents quantitative estimates of the benefits of current restructuring efforts in the PJM states. Much of the benefit from current restructuring is captured by reduced prices to ultimate customers. Constructing reliable estimates of these benefits requires estimating the change in prices to customers due specifically to restructuring, and not due to other factors. The change in electricity retail prices is affected significantly by: the change in wholesale prices, stranded cost recovery, negotiated retail prices, other variables that affect retail prices in all regions, and other factors. The task of capturing the benefits of restructuring requires isolating the price increment (? P) produced by restructuring. [61]

Although ? P in the wholesale market is not directly *measurable*, there are clear *indicators* of efficiency gains and cost reductions in this market. The restructured PJM wholesale market imparts the incentive to minimize cost. In contrast, markets regulated by COS reimburse costs that are prudently incurred. The various indicators such as increased capacity availability (Figure 3) and reduced marginal cost curves (Figure 1) suggest that the restructured PJM wholesale market is successful in reducing costs relative to a regulated market. The composite effect of these efficiency effects is captured in ? P.

In contrast to the wholesale market, the retail restructuring, at least during the transition period, is characterized by a negotiated deal. An important component of the "deal" is the recovery of stranded costs. The "deal" also includes a required price declines to ultimate customers, at least on a temporary basis. Other parts of the "deal" include standard offer prices, price caps, and various default supply provisions. Retail price changes therefore reflect wholesale market efficiencies, the effects of the retail restructuring deal, and the effects of retail competition. Of course, the change in retail prices from 1997 to 2002 also reflects fuel prices, inflation, and other factors that affect electricity prices in other regions.

The stranded cost recovery deal of the three states was reviewed to determine the effect of such recovery on current and future electricity prices. Each of the three PJM states allows for stranded cost recovery. The electric utilities in Maryland and New Jersey divested much of their generating capacity, and hence have small stranded costs. In contrast, the utilities in Pennsylvania retain most of their generating capacity and have much higher stranded costs. Estimating stranded costs requires obtaining specific utility data that is available for PA, but not readily available for NJ or MD. In this analysis, benefits in PA are calculated after stranded costs are recovered and electricity prices decline, but no such calculation is made for MD or NJ.

The benefits from current restructuring efforts include the present cost saving plus the present value of future electricity cost savings that occur from PJM restructuring in wholesale and retail

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[61]This analysis compares the electricity price declines in the PJM states with those of neighboring states that are not restructuring and with the total U.S. The relatively large price declines in the PJM region are a result of successful restructuring in the PJM region and other possible factors. An econometric analysis is required to identify the statistical importance of other factors, but is outside the scope of this study. We have no preliminary indication that "other factors" explain the relatively large cost saving estimated in the PJM region.

markets. The calculation of future benefits is tedious and is explained in the appendix. At this point, we simply sketch the method of calculating future benefits and present the results. The approach begins by using EIA data to determine electricity prices by state and by sector (R, C and I) for year 1997 and again for year 2002, the last year for which a full set of EIA data are available. The PJM region includes the three states of PA, MD and NJ, and Delaware and Washington DC.[62] The increment in electricity price is calculated for each state and each of the three sectors (R, C and I). The 2002 prices are transformed into constant dollars by adjusting for the inflation from 1997 through 2002.

Table 4 shows the cost saving in year 2002 and the present value of future electricity cost savings by sector in the PJM region. The second column shows ? Price in constant dollars by state and sector. The next column shows the cost saving in year 2002, which is estimated as ? Price, from 1997 -2002 times the electricity generation in 2002.[63] As depicted, New Jersey customers saved about $1.4 billion in 2002, relative to 1997 prices, while PA customers saved $993 million. The larger cost saving in New Jersey results from the larger price decline. For the PJM region in total, electricity costs saved in 2002 are about 15 percent of the electricity costs in 2002.

These price declines should produce a long term cost saving that is estimated as the present value of these current price declines times the amount of electricity purchased over time. The electricity price change (? P) from 1997 to 2002 in constant dollars is multiplied by electricity sales in kWh to obtain a total dollar cost reduction in year 2002. The electricity price change is assumed to be constant, to best reflect current restructuring efforts. However, electricity generation is assumed to increase at the national average projected by the EIA. The future monetary stream of cost stream is discounted to convert to present value. This present value of cost saving reflects the benefits of restructuring efforts plus cost reduction due to other factors.

The present value of current cost savings times future electricity consumption is estimated to be $17.8 billion in PA, $13.5 billion in NJ and $3.8 billion in MD. The PA estimates include an estimate of benefits post stranded cost recovery, even though most of that recovery will not be complete for another six years.

A perspective of these benefits is gained by comparing them with total electricity costs as of year 2002. The last column in Table 4 shows the present value (PV) of cost reductions as a percent of year 2002 electricity costs. The PV of cost reduction in NJ is more than twice annual electricity costs. The PV of total cost savings is $38.766 billion, which is 176.37 percent of the customers 2002 electricity bill.

The estimated cost saving to New Jersey customers in year 2002, of about $1.4 billion has been realized, but future benefits are precarious. The decreases in retail prices in New Jersey resulted from a bargain that included initial price declines of 15%. That bargain expired in August 2003,

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[62] We noted above that in year 2002 the PJM region was expanded to include parts of OH ,VA, and WV, but this larger region is not considered in the benefit calculations here.

[63] Electricity generation data are presented in Table A1.

and rates in nominal terms returned to about their initial levels. The four large utility in New Jersey requested significant rate increases, and the Board of Public Utilities has allowed a large share of the requested rate increases.[64] However, the inflation rate from 1997 through 2003 was about 2 percent per year (10% for 5 years), which means that New Jersey customers still have a 10 price decline in electricity rates since 1997 in constant dollars. In addition, with efficiencies achieved in the wholesale PJM market passed forward to customers, some nominal price declines are plausible. Further, the retail price increase in New Jersey in 2003 will provide a much needed

Table 4
Estimating Benefits From Restructuring: PJM Region
(in millions of constant dollars)

	? Price 1997 - 2002 Real ¢/kWh	Saving, 2002 $ million Real	Present Value, 2002 $ mil. Real	Electricity Costs, 2002 $ mil. Real	Percent Saving Col.3/Col.4
New Jersey					
Residential	2.50	$680.14	$6,297.5	$2,464	255.57%
Commercial	2.08	$738.89	$6,841.6	$2,817	242.84%
Industrial	1.22	$139.02	$1,287.3	$992	129.78%
Total	1.97	$1,468.34	$13,595.8	$6,359	213.80%
Pennsylvania					
Residential	1.12	$558.22	$8,192.3	$4,395	193.26%
Commercial	0.82	$359.04	$5,985.8	$3,345	178.93%
Industrial	0.56	$261.50	$5,266.6	$2,513	209.61%
Total	0.70	$993.97	$17,818.2	$10,398	171.36%
Maryland					
Residential	1.27	$327.49	$3,032.3	$1,828	165.87%
Commercial	0.66	$143.91	$1,332.5	$1,361	97.94%
Industrial	0.61	$95.37	$883.0	$558	158.21%
Total	0.97	$622.39	$5,762.9	$3,827	150.60%
Washington DC					
Residential	0.21	$3.81	$35.2	$138	25.51%
Commercial	0.78	$67.25	$622.7	$575	108.37%
Industrial	-0.10	-$0.28	-$2.6	$13	-20.48%
Total	0.66	$74.05	$685.7	$748	91.61%
Delaware					
Residential	1.31	$51.86	$480.2	$275	174.92%
Commercial	0.47	$17.65	$163.4	$202	80.81%
Industrial	0.93	$38.23	$353.9	$165	214.90%
Total	0.82	$97.62	$903.9	$648	139.53%
Total, PJM region		$3,256.38	$38,766.4	$21,980	176.37%

[64] State of New Jersey, Board of Public Utilities, see www.bpu.state.nj.us

incentive towards retail competition, which may ultimately make customers better of than commission mandated price declines. Overall, it appears that with the expiration of the negotiated price declines, New Jersey customers will still see future benefit in constant dollars, but perhaps not as large as indicated above.
The above table presents benefit estimates of restructuring efforts currently in place. On balance, it is likely that the benefits estimates for New Jersey are optimistic. However, the benefit estimates of the other states are probably conservative, and larger benefits are plausible.

An assumption in this analysis is that the estimated price decline (? P) remains constant in perpetuity. Retail prices may decline even further in the future, but some current price declines may not be permanent. To the extent that New Jersey utilities obtain price increases, the benefits from restructuring are reduced. Considering the efficiencies achieved in the restructured wholesale market, a competitive retail market could, at least over time, preserve these wholesale cost reductions and prevent the New Jersey utilities from maintaining the price increases.

A significant share of this cost savings results from a decline in the inflation adjusted (real) cost of electricity. Perhaps this cost decline would have occurred without restructuring. A similar present value calculation is made for the U. S. average, and also for three neighboring states that are not restructuring their electricity markets. These present value estimates reflect the effects on electricity prices due to factors other than restructuring. If restructuring has not reduced electricity prices, such prices in the PJM region would approximately follow the U.S average, or that of neighboring non-restructuring states. Actually, about one-half of the states in the U.S. are undertaking some type of restructuring effort in their electricity sectors. The U.S. average electricity prices probably reflect some downward effects due to various state restructuring efforts. The benefit measure applied to the PJM region does not exactly measure absolute restructuring effects, but rather effects relative to all other states. Hence, benefits estimated here are benefits relative to the entire U.S.

The results in Table 4 indicate that the largest benefit, relative to annual energy cost, is in the residential sector. As noted above, low income households spend a much larger share of their income on energy than high income households. Hence, the greatest beneficiaries of restructuring may be low and moderate income households. However, should retail competition develop to its potential, C and I customers may be significant beneficiaries.[65]

Estimating Benefits: Non-restructuring States
The effects of restructuring in the PJM region are estimated by making similar PV calculations as above, but for neighboring states and for the U.S. average. States located near the PJM region that

[65] A contention is that residential customers currently receive a cross subsidy from C and I customers, and this cross subsidy would disappear with retail competition.

are not restructuring include Kentucky, North Carolina and Tennessee. The EIA identifies these three states as having "restructuring not active".[66]

As noted above in Section 3, the Energy Policy Act of 1992, as well as various FERC orders, encourages some restructuring of wholesale markets that affects these three states, as well as the PJM region. As a result of FERC efforts to encourage open access to transmission, some efficiency gains are probably occurring in these three states. By contrasting these three states with the PJM region, we are not isolating the affects of all restructuring. Instead, we are identifying those effects unique to the PJM region that are over and above the restructuring effects in other regions. This analysis primarily quantifies the cost saving resulting from the PJM auction market and retail competition. [67]

These EIA data are used to construct electricity price data for these three states and for the U.S. average by sector for the years 1997 and 2002. The same method as above is used to construct a benefit estimate in each state and sector. By comparing ? P in these three states with the PJM region, but we are capturing the effects of the PJM auction market as well as cost reductions from retail competition. We are not capturing the effects of FERC actions that apply to all states.

Table 5 shows calculations of benefits price declines in three nearby and non-restructuring states. These states and the total U.S. experienced a decline in electricity prices in constant dollars from 1997 through 2002, and consequently consumers receive positive benefits. The estimated benefits are about 46 percent of 2002 electricity costs in TN, NC and KY, and in the total U.S. However, in the restructuring states, benefits are 176.37 percent of 2002 electricity costs.

The data in Table 5 indicates that electricity price declines from 1997 through 2002, without restructuring, produce an average value to customers about equal to 46 percent of their 2002 electricity bill. We therefore assume that 46 percent of the PJM electricity cost would have been saved without restructuring. That is, $10.11 billion would be saved in the PJM region without restructuring.[68] With this amount subtracted from total cost saving, the benefit of restructuring in the PJM region is estimated to be $28.656 billion. This benefit estimate equals the total cost saving in PV terms minus estimated saving without restructuring.

To express benefits on a household level, we begin with benefits in the residential sector, Table 4, in year 2002 and future benefits in present value for. Using the results from Table 5, we subtract the estimated cost saving that would have occurred in the absence of PJM restructuring. Using data from Statistical Abstract, there were 4.777 million households in PA in year 2000. Using total costs reduced and number of households, we estimate that residential households in Pennsylvania

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[66] See the EIA website, www.eia.doe.gov "Status of State Electric Utility Deregulation/Restructuring Activity"

[67] The differences between these non-restructuring states and the PJM regions include fuel prices, state environmental regulations and other factors. Such factors affect primarily the level of relative prices. This analysis compares price increments from 1997 to 2002 between regions, where a major factor, but not only factor is PJM restructuring. A more extensive analysis using econometric methods could perhaps more precisely isolate the effects of PJM restructuring.

[68] The estimate of $10.11 billion is 46 percent of $38.766 billion, which is total PV of cost saving in Table 4.

saved, on average, about $117 on their electric bill in year 2002.[69] Each household in PA will save, on average, about $1,262, measured as present value of the sum of future saving.[70]

This evidence indicates that the restructuring states in the PJM region are experiencing cost reduction benefits with a monetary value that exceeds electricity costs for one year. Electricity prices reflect the influence of several factors and restructuring effects are not easily isolated. If the PJM region relaxed its environmental standards, or experienced a reduction in fuel prices relative to other regions, electricity prices could decline for reasons other than restructuring.

Table 5
Estimating Price Reduction Benefits From Non-Restructuring States
(In millions of constant dollars)

	? Price 1997-2002 Real ¢/kWh	Cost Saving Year 2002 $ mil. Real	Present Value, 2002 $ mil. Real	Electricity Costs, 2002 $ mil. Real	Percent Saving Col. 3/Col. 4
Kentucky					
Residential	0.46	$114.24	$1,057.75	$1,283.75	82.40%
Commercial	0.44	$64.21	$823.23	$706.38	116.54%
Industrial	-0.06	-$27.99	-$358.83	$1,255.38	-28.58%
Total	0.12	$106.67	$1,522.15	$3,386.42	44.95%
North Carolina					
Residential	0.55	$225.17	$2,084.89	$3,692.94	56.46%
Commercial	0.47	$148.58	$1,904.81	$2,348.81	81.10%
Industrial	0.38	$134.08	$1,718.98	$1,364.27	126.00%
Total	0.32	$351.20	$5,708.68	$7,543.26	75.68%
Tennessee					
Residential	0.16	$64.62	$598.37	$2,298.48	26.03%
Commercial	0.03	$7.19	$92.15	$1,593.02	5.78%
Industrial	-0.09	-$29.01	-$371.93	$1,286.49	-28.91%
Total	0.06	$58.13	$318.59	$5,269.49	6.05%
Total		$515.99	$7,549.42	$16,199.16	46.60%
United States					
Residential	0.70	$8,397.48	$77,754.47	$98,101.73	79.26%
Commercial	0.37	$4,036.95	$51,755.76	$79,952.70	64.73%
Industrial	0.11	$1,065.95	$13,666.02	$43,945.62	31.10%
Total	0.27	$9,137.16	$105,509.94	$228,523.08	46.17%

[69] The table shows savings in the PA residential sector to be $558.22 million in year 2002, and there were 4.777 million households in PA in year 2000, for an average saving of $117 per household in 2002. Household data are obtained from the U.S. Bureau of Census, *Statistical Abstract in the United States,2002,* Washington DC, Table No. 53, p. 50.

[70] Lifetime saving per household is estimated as present value of savings in PA in 2002 ($6,027 million) divided by number of households (4.777 million).

The estimated benefits may be considered tentative pending a thorough analysis of all possible factors that could account for the relative price declines in the PJM region.[71] However, we see that the restructuring states are obtaining much larger electricity cost reductions than the U.S. average and the three neighboring states that are not restructuring.

These results, although preliminary and sensitive to data limitations, are informative. The PJM region is not yet receiving the potential benefits from retail competition; it is not yet receiving benefits from price-demand response, and it is not receiving benefit from a restructured market for total capacity (next section). Further, we have not captured the benefits to states other than PA from the completion of stranded cost recovery. Most of the potential benefits from restructuring will derive from future efforts. Even so, the benefit from present restructuring indicates that the PJM region is gaining a competitive advantage in electricity prices relative to some nearby states that are not restructuring.

5.4 Macroeconomic Benefits From Restructuring

The benefits estimated above are merely the first-round, or direct impact, of declining electricity prices. The additional macroeconomic effects of reduced electricity prices can be substantial. Maloney et al, in their study of competition in the national electricity market concluded that price declines in electricity and its increased use "…translate in to GDP increases of 0.8 and 2.6 percent respectively."[72] The macroeconomic effects estimated by Maloney et. al. include this growth effect on GDP and reduced inflation, increased productivity, reduced unemployment and dynamic gains from competition.

The macroeconomic implications of successful restructuring are suggested here to be important and to increase over time. During the first decade of restructuring, the macro effects are moderate because restructuring is implemented only gradually. When restructuring includes an efficient price-demand response mechanism, and when stranded costs are paid off, the macroeconomic benefits of restructuring should be substantial. These macroeconomic benefits are in addition to the "first-round" effects that are captured as consumer surplus. The initial effect of an electricity price decline is to increase consumer surplus of R, C and I customers. When the cost saving improves productivity (C and I customers) and is spent, it produces subsequent round macroeconomic benefits. As a first approximation, a simple multiplier of 2 is reasonable, which indicates that the total economic benefits are about twice the initial benefits to customers.

Appendix: Estimating the Benefits From Restructuring.

[71] Some reviewers suggested searching for other explanations of electricity price declines, but a thorough analysis would require estimating an econometric model that explains price changes in numerous states and statistically captures the restructuring effort in the PJM region.

[72] Maloney, Michael T. and Robert E. McCormick, *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Industry,* Volume 1, Washington DC, Citizens for a Sound Economy, 1996.

This appendix explains in more detail the calculations used to obtain the cost saving estimates in Tables 4 and 5.

Benefits of restructuring are calculated as the monetary value of reducing prices to ultimate customers from the restructuring efforts that have occurred to date. Future efficiency improvements are not considered here. However, current restructuring efforts result in price declines that will continue into the future with no additional effort. The future benefits from existing efforts are captured by estimating the present value (PV) of future benefits discounted to 2002. Present value is expressed in the equation:

Equation (1) $$PV_{2002} = \underset{t=0}{\overset{8}{?}} \; ?P \, Q_{2002+t}(1+g)^t/(1+r)^t$$

where ? P is the reduction in the price of electricity,
Q_t is kWh of electricity used in year t
g is the annual projected growth rate in electricity consumption
r is the discount rate, and
t is the year minus 2002.

In this equation, the base year is 2002; hence dollars saved after 2002 are discounted. The equation also expresses the price decline achieved by restructuring as a constant obtained in perpetuity. This ? P applies to each unit of electricity consumed, where electricity consumption will increase at the annual rate of g. Future cost reductions, because they occur in the future, are discounted to convert to year 2002, using the discount rate r.

The principles of corporate finance provide a widely accepted method for estimating an appropriate discount rate. Following the popular corporate finance text of Brealey and Myers, we begin by specifying the Capital Asset Pricing Model (CAPM), which is

$$r_i = r_f + ß_i (r_m - r_f),$$

where

r_i = the discount rate on project i
r_f = the risk free rate of return
$ß_i$ = beta for project i
r_m = the rate of return on the stock market.

This equation indicates that the appropriate discount rate for an investment is equal to the risk free rate of return plus and adjustment for risk as measured by $ß_{i,}$ which is a measure of risk. On average, ß = 1, because the rate of return of all investments on average equals the market rate of return. The risk free rate of return is usually understood to be the U.S. Treasury Bill rate of about 3.9 percent per year nominal and 0.8 percent real. The market rate of return is the long run rate of return on common stocks (S&P 500), which has been 13.0 percent per year nominal and 9.7 percent per real from 1926 – 2000.[73]

Electricity is purchased in the commercial and industrial sectors by all businesses in these sectors. The appropriate discount rate should reflect all businesses on average, and hence ß = 1 for an appropriate average rate. Using ß = 1, the appropriate discount rate for the commercial and industrial sectors is 13 percent nominal and 9.7 percent real.

The appropriate discount rate for the residential sector cannot be assumed to be equal to the corporate discount rate. The extensive literature on household discount rates indicates that households have high discount rates for energy saving investments. Such investments reduce subsequent energy cost, similar to a price decline in electricity. Energy saving investments are characterized by risk and illiquidity; they are typically fixed and irreversible. These characteristics at least partially explain high consumer discount rates. These properties do not characterize a decline in residential electricity prices, because households do not have to make the initial investments. Household discount rates that are appropriate for energy conservation investments, of say 20 to 30 percent, are probably too high to apply to energy cost reductions that do not require consumer investments.

Hence the real discount rate for C and I customers is 9.7 percent per year, the long term real rate of return on common stocks. For residential customers, the real rate is assumed to equal an additional 3 percent, or 12.7 percent per year in constant dollars. Ordinarily higher discount rates are required for households because of their opportunity cost.[74]

The growth rate of electricity consumption is projected by the EIA to be 1.9 percent per year from 2001 through 2020.[75] This growth rate is applied to the cost saving in electricity consumption (? PQ_t) to indicate that costs saved increase at 1.9 percent per year.

The actual discount rates used to compute present value of the restructuring benefit equal the real discount rate minus the growth rate in cost saving. These rates equal 7.8 percent for the commercial and industrial sectors and 10.8 percent for the residential sector.

The present value of cost savings can be calculated using equation (1), with the caveat the cost savings should accrue into the indefinite future. With this caveat, integral calculus provides a more appropriate tool. In the case of a constant and perpetual revenue flow, mathematical

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[73] Richard Brealey and Stewart Meyers, *Principles of Corporate Finance*, McGraw Hill Book Co., Seventh Edition, 2003, p. 155.

[74] The high consumer discount rate for energy conservation investments is a consequence of consumers foregoing basic necessities to make such investments. In the case of restructuring, electricity prices decline immediately, and consumers have no such opportunity cost.

[75] Energy Information Administration, *Annual Energy Outlook 2003: With Projections to 2025,* U.S. Department of Energy, Washington DC, DOE/EIA-0383(2003), projection obtained on line.

economics texts show that a convenient and readable equation can calculate present value.[76] The present value in year 2002 of a constant revenue flow in perpetuity is expressed as

Equation (2) $PV_{2002} = ?P\,Q_{2002}/r$,

where r is the discount rate. Hence, to calculate the present value of cost savings we simply need to estimate cost saved per kWh, kilowatt hours of electricity used in year 2002 by state and by sector, and the real discount rate adjusted for electricity growth. These calculations are readily embedded in a spreadsheet.

Nominal electricity price data were constructed from an EIA data file containing electricity sales and revenues by state, by sector, by month and by year.[77] Nominal prices for 2002 were adjusted for inflation by using the percentage change in the GDP price deflator from 1997 to 2002, which is 8.5 percent.[78] This calculation produces the change in electricity prices from 1997 to 2002 in constant dollars.

Equation (2) also provides an intuitive expectation and understanding of the benefit estimates. The principle is: if restructuring reduces the ultimate customer's annual electricity bill by a percent that equals the customer's discount rate, then the PV benefit of restructuring equals energy costs for one year for each customer. For example, if a residential customer has an annual electricity bill of $2,000 and restructuring reduces energy costs by 10 percent, then cost saved is $200 per year (? P Q = $200) in perpetuity. Using equation (2) the PV of $200 per year at a 10 percent discount rate is $2,000. As a very rough approximation, we may expect that the benefits of current restructuring efforts to be about equal to annual electricity costs for each customer.

Estimates of the present value of electricity cost reductions are presented in Table A1, which are based on an Excel spreadsheet. Table 4 contains the same data as Table A1, but has several columns hidden. The data in Table A1 first depict electricity prices in 1997 using EIA data. The next two columns show nominal and real electricity prices. The columns denoted ? P columns B – D show the real electricity price change from 1997 to 2002. The next column shows electricity generation. The data are constructed from the same EIA data file as the price data. Present value of cost savings is estimated using equation above, where each of the three variables is defined. In the next column – PV Stranded Cost Recovery – I calculate the benefits of price decreases after stranded costs are recovered. With available data this calculation is made only for PA.

In Table A1, electricity costs are first depicted in nominal dollars, but then converted to constant dollars using the same inflation factor used for electricity prices. The notes in Table A1 denote ? Price 97-02 as 0.915, which derives from the Department of Commerce price index showing 8.5

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[76] Alpha C. Chiang, *Fundamentals Methods of mathematical Economics*, Second Edition, McGraw-Hill, 1974, p. 459.

[77] Data were obtained from the EIA data file: Historical 1990 through Current Month Retail Sales, Revenues, and Average Revenue per Kilowatthour by State and by Sector .

[78] According to Table C.1, *Survey of Current Business,* U.S. Department of Commerce, August 2003, the GDP chain-type price index in 1997/2 was 101.82 and it increased to 110.48 in 2002/2, which is an 8.5% increase.

percent increase in the GDP deflator. The last column in Table A1 is the percent saving and is estimated as the PV of saving divided by real electricity costs.

The notes at the bottom of Table A1 contain some parameters used in the Excel spreadsheet calculations. For example, the discount rates are 9.7 percent for the C and I sectors, but 12.7 percent for the residential sector. Each rate is decreased by 1.9 percent to allow for electricity growth.

Much of the benefit of restructuring is delayed until utilities recover their stranded costs. The scheduled completion of stranded cost recovery varies by state, by utility and by year. Available data from PA supports at least a tentative estimate of dollar benefits when stranded cost recovery is complete. The data from MD and NJ are so precarious that estimates are not presented. However, PA has by far the largest amount of stranded costs.

The methodology for estimating dollar benefits post stranded cost recovery is admittedly tedious. We first estimate that the average decline in the price of electricity in PA will be 1.454 cents per kWh, and this price decline will occur in year 2009. The ? P post stranded costs is denoted ? PS, and is estimated from competitive electricity cost estimates by utility for five PA utilities. Data are obtained from Hanger and Adels, and ? PS is estimated as the weighted average cost decrease as of year 2009, where the weights are the sales share of each electric utility in PA.[79] The expected average price decline in electricity in PA is 1.454 cents/kWh in 2009.

The present value of this price decline is estimated, as in equation (2), by multiplying ? PS times electricity sales by sector beginning in year 2009 and continuing in perpetuity. The PV as of 2009 is then discounted back to year 2002. These future benefits are discounted using a 9.7 percent rate for the commercial and industrial sectors and a 12.7 percent rate for the residential sector.

The effect of discounting these post-recovery benefits is a reduction of roughly 50 percent. Hence stranded cost recovery has a major effect in redistributing the benefits of restructuring. Even so, the benefits of post cost recovery are $3 billion in the residential sector in PA, and more than $2 billion in the commercial and industrial sectors, for a total of $8.6 billion.

Estimating the present value of the benefit of completing the stranded cost recovery requires first estimating this present value as of the future year T, when such recovery is complete. The present value equation is

Equation (3) $$PV_T = ?PS\ Q_T / r,$$

where ? PS is used to denote the change in the price of electricity from completing the stranded cost recovery at year T, when it is completed. Year T varies between states and even utilities, but

[79] John Hanger and Peter Adels "The Skinny on Caps and Stranded Costs" *Energy Pulse*, http:/www.energypulse.net , August 7, 2003.

it is typically from year 2006 to year 2010. Some utilities have no stranded costs or recover then prior to 2006.

In equation (3), Q_T refers to the quantity of kWh used in year T, and r is the same discount rate as used above. Q_T is estimated by electricity sales in base year of 2002 when most recent data are available and assuming sales to grow at an annual average U.S. rate of 1.9 percent per year.

Equation (3) provides a present value calculation for the future year T, but this value must be discounted back to the present year of 2003. Cost savings that occur in the future are of lower value today. The present value as of year 2002 is

Equation (4) $$PV_{2002} = PV_T\, e^{-r(T - 2002)}.$$

Equations (3) and (4) provide a recipe for estimating the PV of benefits due to the completion of stranded cost recovery. In this calculation, the electricity price decline (? PS) is particularly critical.

Electricity sales in year 2009 (Q_T) is estimated from 2002 sales by sector, assumed to grow at the national average (EIA estimate) of 1.9 percent per year. This growth rate produces a growth factor of 1.1422, which is multiplied by 2002 generation to estimate 2009 generation. Electricity cost saving ? PS Q_T as of 2009 is assumed to grow in perpetuity at annual rate 1.9 percent per year and is discounted using real C and I rates of 9.7 percent and household rates of 12.7 percent. The present value as of 2009 is then discounted back to the base year of 2002 using the weighted average discount rate (12.77 percent) of the three sectors.

The method used for the calculations in Table A2, are similar to those in Table A1, and hence are not discussed in detail.

Table A1
Estimating Benefits from Restructuring in the PJM Region

	Price Electricity 1997	Price Electricity 2002	Price Electricity Real, 2002	? Price columns B - D	million kWh 2002	Present Val. (mil.)	PV Stranded Cost Rec.	Electricity Costs 2002	Electricity Costs 2002,Real	Percent Saving
New Jersey										
Residential	12.04	10.43	9.54	2.50	27,243	$6,297.55	NA	$2,693.0	$2,464	255.57%
Commercial	10.35	9.04	8.27	2.08	35,551	$6,841.59	NA	$3,079.0	$2,817	242.84%
Industrial	8.11	7.53	6.89	1.22	11,395	$1,287.27	NA	$1,084.0	$992	129.78%
Total	10.53	9.36	8.56	1.97	74,702	$13,595.76	NA	$6,950.0	$6,359	213.80%
Pennsylvania										
Residential	9.9	9.6	8.78	1.12	50,020	$5,168.73	$3,023.61	$4,803	$4,395	193.26%
Commercial	8.41	8.3	7.59	0.82	44,027	$3,324.45	$2,661.34	$3,656	$3,345	178.93%
Industrial	5.89	5.83	5.33	0.56	47,070	$2,421.27	$2,845.29	$2,746	$2,513	209.61%
Total	7.99	7.97	7.29	0.70	142,515	$9,203.43	$8,614.74	$11,364	$10,398	171.36%
Maryland										
Residential	8.33	7.72	7.06	1.27	25,864	$3,032.31	NA	$1,998	$1,828	165.87%
Commercial	6.86	6.78	6.20	0.66	21,928	$1,332.53	NA	$1,487	$1,361	97.94%
Industrial	4.21	3.93	3.60	0.61	15,531	$883.04	NA	$610	$558	158.21%
Total	6.98	6.57	6.01	0.97	64,267	$5,762.91	NA	$4,182	$3,827	150.60%
Washington DC										
Residential	7.87	8.37	7.66	0.21	1,800	$35.24	NA	$151	$138	25.51%
Commercial	7.43	7.27	6.65	0.78	8,645	$622.72	NA	$628	$575	108.37%
Industrial	4.42	4.94	4.52	-0.10	283	-$2.62	NA	$14	$13	-20.48%
Total	7.39	7.35	6.73	0.66	11,140	$685.68	NA	$818	$748	91.61%
Delaware										
Residential	9.22	8.65	7.91	1.31	3,973	$480.16	NA	$300	$275	174.92%
Commercial	7.19	7.34	6.72	0.47	3,724	$163.41	NA	$221	$202	80.81%
Industrial	4.822	4.25	3.89	0.93	4,096	$353.94	NA	$180	$165	214.90%
Total	7	6.75	6.18	0.82	11,851	$903.91	NA	$708	$648	139.53%
						$38,766.44		$24,022.0	$21,980	176.37%
Sales g factor	1.1422				Discount Rates					
delta PS	1.454				r(Res) = .127	0.108				
r aggregate	0.1277				r(Com) = .097	0.078				
disc fact T-2003	0.4648				r(Ind) = .097	0.078				
? Price 97 - 02	0.915				elect gr. = 1.9%/yr					

Table A2
Estimating Cost Reduction Benefits From Non-Restructuring States

	Price of Electricity 1997	Price of Electricity 2002	Price Electricity Real, 2002	? Price columns B - D	Generation million kWh 2001	Present Value $ mil. Real	Electricity Costs 2002, Nom.	Electricity Costs 2002,Real	percent Cost Saving
Kentucky									
Residential	5.58	5.6	5.12	0.46	25,052	$1,057.75	$1,403	$1,284	82.40%
Commercial	5.29	5.3	4.85	0.44	14,577	$823.23	$772	$706	116.54%
Industrial	2.8	3.13	2.86	-0.06	43,766	-$358.83	$1,372	$1,255	-28.58%
Total	4.03	4.27	3.91	0.12	86,755	$1,522.15	$3,701	$3,386	44.95%
North Carolina									
Residential	8.03	8.17	7.48	0.55	40,611	$2,084.89	$4,036	$3,693	56.46%
Commercial	6.43	6.51	5.96	0.47	31,388	$1,904.81	$2,567	$2,349	81.10%
Industrial	4.71	4.73	4.33	0.38	35,095	$1,718.98	$1,491	$1,364	126.00%
Total	6.48	6.73	6.16	0.32	109,050	$5,708.68	$8,244	$7,543	75.68%
Tennessee									
Residential	6.03	6.41	5.87	0.16	39,202	$598.37	$2,512	$2,298	26.03%
Commercial	5.91	6.43	5.88	0.03	27,072	$92.15	$1,741	$1,593	5.78%
Industrial	3.81	4.26	3.90	-0.09	33,004	-$371.93	$1,406	$1,286	-28.91%
Total	5.31	5.74	5.25	0.06	100,396	$318.59	$5,759	$5,269	6.05%
					Total	$7,549.42	$17,704	$16,199.16	46.60%
United States									
Residential	8.43	8.45	7.73	0.70	1,202,647	$77,754.47	$107,215	$98,101.73	79.26%
Commercial	7.59	7.89	7.22	0.37	1,089,154	$51,755.76	$87,380	$79,952.70	64.73%
Industrial	4.53	4.83	4.42	0.11	964,224	$13,666.02	$48,028	$43,945.62	31.10%
Total	6.85	7.19	6.58	0.27	3,369,781	$105,509.94	$249,752	$228,523.08	46.17%

6. Total Capacity and Optimum Reserve Margins

The restructuring of electric utilities could provide significant benefits to customers by making more efficient use of generating capacity and other resources. The capital costs of generating capacity are immense, and any significant reduction in these costs per kilowatt hour would reduce the price of electricity to ultimate customers. However a reduction in total generating capacity could also reduce the ability of the system to meet large unexpected increases in the demand for electricity. This section reviews the current market for total capacity in PJM to determine whether restructuring is providing optimum benefits to customers.

Two specific conclusions are suggested:

1. The PJM region does not optimize benefits to customers in this market because it does not apply an ordinary demand curve for reliability consistent with customer preferences. The application of such a demand curve would provide much needed demand response, and reduce the cost of supplying electricity.

2. The PJM demand response effort is thus far not highly cost effective. The PJM emergency option has a design flaw that precludes long run cost-effectiveness. Instead, real time retail prices may be more effective.

The point of this section is only partially to develop the above two points, but also to explain why successful restructuring is difficult to achieve with respect to capacity reserve margins.

Electric utilities maintain a significant amount of generating capacity in excess of expected peak requirements. The economic merit of the capacity reserve margin is subject to strongly held, but divergent views. Three views are noted:

1. Most persons directly associated with the supply side of the electricity market, including, PSC officials, legislators, utility managers and consumer advocates, strongly endorse the use of large capacity reserve margins to ensure reliability. Such groups may oppose the use of the price mechanism to reduce reserve during periods of peak use.

2. The PJM power pool clearly recognizes the need to obtain demand response in capacity and energy markets to improve efficiency and to reduce market power. A critical component of this demand response is the need to use price signals to reduce price spikes during periods of extreme peak demand.

3. The position of mainstream economists is that the historic rule of thumb on reserve margins makes no economic sense, and reserve margins should instead be derived from standard optimization tools. Chao and Wilson provide a formal demonstration of this result,[80] and Munasinghe uses an optimization model to determine optimum reliability based on costs and

[80] Chao, Hung-po and R. Wilson, "Priority Service: Pricing Investment and Market Organization", *The American Economics Review*, Vol. 77, 1978, pp. 899-916.

benefits.[81] The use of an ordinary demand curve to determine reserve margin would add much needed price-demand response.

The strongly held view by most interested parties is to maintain a high level of capacity in reserve. This view is politically correct and is accepted by PJM. However, maintaining a high reserve margin without price sensitivity results in price spikes in the capacity market, and high costs to customers. This section shows that the application of standard economic demand analysis could provide demand response in the capacity market, reduce price spikes, and still increase customer value – consumer surplus – from purchasing electricity.

6.1 Reserve Margins With Regulation

The PJM restructuring effort in the wholesale market uses an efficient market process to produce market outcomes. First, there is explicit recognition of the textbook efficiency condition that price equals marginal cost (P = MC). That is, if a market is structured so that the price paid for a resource equals its marginal cost of production, consumers receive maximum benefits.[82] Second, the restructuring effort is designed to attain this equality in various submarkets. The method used by PJM to ensure marginal equality of prices and costs is an auction market, where energy, capacity, and other resources are priced. PJM uses a real time and day-ahead market to determine prices of energy, and other auction markets to determine prices of capacity and other services. This market price equals the last bid accepted, which is marginal supply cost, and all resources used receive the same price. Considering the large share of spot and day-ahead transactions, there is every reason to assess the PJM effort as successful in this area.

PJM uses this auction market process to determine capacity, energy choices and the choices of energy related services. However, PJM does not use this process to determine the target level of reserve margin capacity. Instead, reserve margins appear to be determined by a rule of thumb carried over from COS regulation. This rule of thumb is the 1 in 10 rule which states that utilities should maintain a reserve margin of excess capacity so that outages will equal only 1 day (24 hours) in 10 years. This rule of thumb results in a capacity target being equal to 118% of required demand, or, an excess reserve margin of 18%.[83] In the PJM region, the target level of reserve capacity is set exogenously, according to this rule of thumb. This target level of capacity is not price sensitive.

Traditional regulation of electric utilities encourages over building. This incentive results in a level of capacity reserve margin where cost exceeds value to customers. Furthermore, COS regulation contains no market incentives to optimize the level of reserve margin. The demand for electricity is highly volatile, with large variations occurring daily, seasonally and annually, in addition to purely random variations. The historical approach used by electric utilities to

[81] Mohan Munasinghe, "Optimal Planning, Supply, Quality and Shortage Costs" *The Energy Journal, Special Issue On Electricity Reliability,* Vol. 9, 1988, pp. 43-75.

[82] This marginal equality is necessary for maximizing consumer benefits, but not sufficient. The absence of market power is also required for maximum consumer benefits.

[83] PennFuture, "Throwing a Curve" Vol. 5, No. 12. see www.pennfuture.org

accommodate these extensive demand swings was to hold a large amount of capacity in reserve, at least sufficient to meet random increases in demand.

Utilities estimate an expected peak demand and then build generating capacity to meet this load plus an additional reserve margin. The historical rule of thumb reserve margin was the 1 in 10 rule. With flat retail prices, reliability is obtained by a reserve margin in excess of peak that would prove insufficient in 1 day in 10 years. The regulatory incentive to maintain such a reserve margin is to assure reliability.[84] Of course, the capital costs of this reliability entered the rate base and receive an allowed rate of return.

6.2 Priority Service – The Energy Journal Special Issue

In 1988, the Energy Journal produced a Special Issue on Electricity Reliability that contains 12 articles that address issues relating to electricity reliability. The main conclusions of these articles are relevant here.

1. The value of electricity to customers is measured as their willingness to pay (WTP). The articles emphasize this point, and indeed WTP is the standard measure of benefits of any market change. The value of a change in service reliability is measured as the change in WTP for that service reliability.
2. The optimal price of electricity is equal to the marginal cost of providing it. This MC pricing result is basic proposition in economics.
3. The optimal level of service reliability is determined by equating the marginal WTP of consumers for improved reliability with the marginal cost of obtaining it.[85]
4. Differentiated levels of service reliability can provide net benefits to customers and to suppliers of electricity. Munasinghe and Sanghvi note that practically all studies of outage costs conclude that the distribution of preferred reliability varies with the type of customer, their usage level and their business.
5. Customer needs for reliability and quality service vary widely across customers.[86] As a representative conclusion, Keane, MacDonald and Woo conclude that voluntary load management programs can effectively allocate scarce capacity during peak periods.[87]
6. Doane, Hartman and Woo estimate the value of residential households to accept reduced reliability and find that outage costs are about ten times higher than reported in other studies.[88] This result is important. Households may have a relatively low value for increased

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[84] As such, there is currently a debate in the industry whether public financing would be appropriate for investments for reserve margins used for reliability purposes in a competitive generation market.

[85] Mohan Munasinghe, Chi-Keung and Hung-po Chao, "Guest Editors' Introduction", *The Energy Journal, Special Issue On Electricity Reliability,* Vol. 9, 1988, pp. i-iv

[86] Mohan Munasinghe and A. Sanghvi, "Reliability of Electricity Supply, Outage Costs and Value of Service: An Overview," *The Energy Journal, Special Issue on Electricity Reliability,* Vol. 9, 1988, p. 7.

[87] Dennis Keane, Leslie McDonald and Chi-keung Woo, "Estimating Partial Outage Cost With Market Research Data" *The Energy Journal, Special On Electricity Reliability Issue,* Vol. 9, 1988, pp. 151-159.

[88] Michael J. Doane, Raymand S. Hartman and Chi-Keung Woo, "Household Preference for Interruptible Rate Options and the Revealed Value of Service Reliability" *The Energy Journal, Special On Electricity Reliability Issue,* Vol. 9, 1988, pp. 121-134.

reliability, but they apparently attach a high value to existing reliability. The implication is that any restructuring change that reduces apparent reliability, must be done with caution, and should probably be done on a customer voluntary basis.

These Energy Journal articles imply that marketers could successfully offer ultimate customers variations in the quality and reliability of service as component of bundled service.

6.3 Excessive Reserve Margins and the Principal Agent Problem

The regulatory system presumably targets excess reserve margins to maximize net benefits. However, the reserve margin that maximizes net benefits to decision makers does not necessarily maximize net benefits to customers. Reserve margins have both cost and risk. The higher the reserve margin the higher the cost, because the capital cost must be reflected in rates. However, high reserve margins also reduce the risk of being unable to meet a large unanticipated increase in load. Reserve margins therefore trade off high cost for reduced risk.

The preferred cost-risk tradeoff of regulatory officials does not necessarily correspond with the preferences of utility customers. Utility managers and utility commissioners prefer high excess reserves to avoid any possibility of not meeting demand. Customers however, may prefer lower rates even at the expense of less than ultra-high reliability. Customers and policy makers each benefit from a reliable electric system. However, a reliable electric system is particularly important to public officials, because reliability is their responsibility and because they avoid criticism from system failures. The costs of providing a super high level of reliability are borne by customers, because customers must pay higher rates to support the reserve margins. Customers are therefore likely to prefer much lower reserve margins than policy makers.

Stated another way, utility commissioners and legislators face asymmetric risks with respect to reserve margins. If reserves are too high, policy makers pay little cost, but customers pay higher rates. If reserve margins are too low, producing occasional service disruptions, the public blames the utilities, commissioners and perhaps legislators. Optimum reserve margins are probably lower from a customer perspective than from a policy maker perspective. Lower margins require lower capital investments, which directly benefit customer with reduced rates. For many customers, the costs of an occasional reserve deficiency are a good trade off for permanently lower rates.

The differing priorities between utility officials and customers indicate that utility regulation is subject to the principal agent problem. The principal-agent problem is a regulatory failure, just like the market failure of environmental degradation in the form of external costs of air and water pollution. Utility customers are the principal; utility commissions are their agents, who supposedly regulate utilities with the objective of maximizing long run benefits to customers. However, the incentive of public officials is to maintain high excess reserve margins to reduce the risk of unmet demand. Customers also prefer to avoid conditions of unmet demand, but customers also prefer not paying the high rates required to support excessive reserve margins.

The above discussion considers customers as homogeneous; however, customers have different preferences with respect to reliability. As several of the Energy Journal Special Issue articles emphasize, reliability risks impose different costs on different customers. Customers that make extensive use of computers and networks require a super high level of reliability (nine nines as it is described in the trade), whereas lower and middle income households are likely to benefit from lower reserve margins and correspondingly lower rates. Priority service would provide a high level of reliability to customers willing to pay for it, and a lower level of reliability to customers who place less value on reliability.

6.4 The Economics of Optimum Reserve Margins

The economically efficient reserve margin cannot derive from a rule of thumb, but instead derives from the same efficient market process that PJM uses in other submarkets. The purpose of reserve margins is to contribute to the reliability of supplying power, particularly during periods of peak demand.[89] The optimum level of reserve margin is determined by equating the marginal cost (MC) of providing reliability with the marginal value of customers for this increased reliability. The benefit of reliability to customers is measured by their willingness to pay for improved reliability.

The marginal cost of providing reliability is the MC of capacity during the peak period, as determined in the auction market. The occasional price spikes in the capacity market are likely to produce marginal cost in excess of its reliability value to customers.

The Energy Information Administration presents an analysis that calculates the optimum reserve margin consistent with customers' willingness to pay.[90] The EIA approach is not intended to be new, but rather to apply conventional marginal analysis. In the EIA analysis, customers have an ordinary demand schedule for reliability, just like they have for all other goods. Less reliability is demanded at higher prices and more reliability is demanded if it is cheaper. As such, less reliability and excess reserves would be demanded by customers when prices spike. Further, where capacity is determined by a rule of thumb, the amount of capacity is likely to exceed customers' marginal willingness to pay for it.

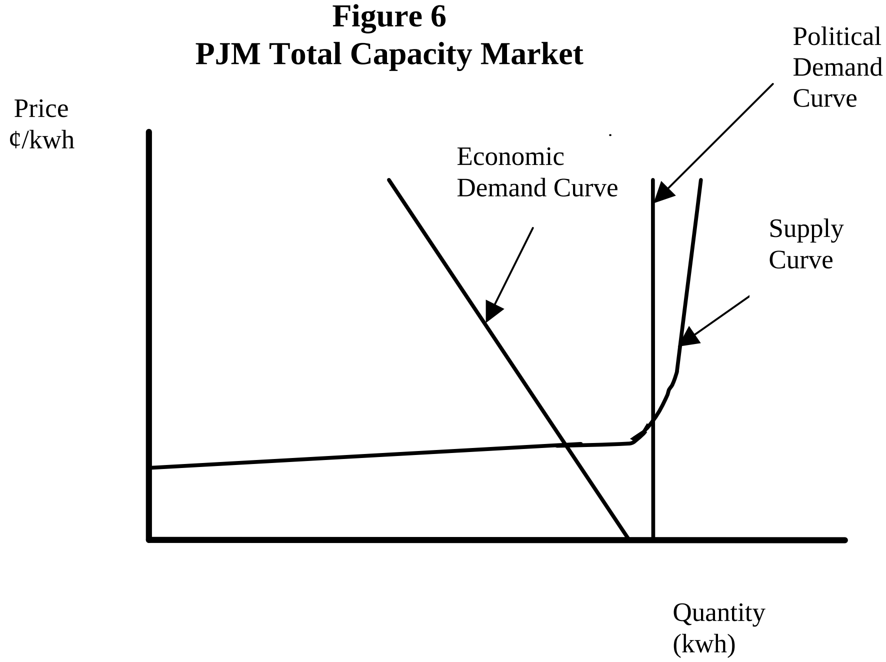
Customers' demand for reliability is reflected in their demand curve for capacity reserve margin. Figure 5 depicts a supply and demand curve for reserve margin capacity during peak periods. The political demand curve is vertical to reflect the price-insensitive capacity margin demanded by the PJM pool. This demand curve is termed a political demand curve because it is imposed by the PJM Interconnection. The vertical demand curve for reserve margin also applies to a market subject to COS regulation.

The infinitely inelastic political demand curve reflects the decision by PJM to obtain a given amount of capacity regardless of price. The presumption is that customers are best served by a given reserve target regardless of what they have to pay for it.

[89] Reserve margins affect system reliability during peak periods, but overall system reliability is affected mostly by the distribution system. Power outages result primarily from failures in the distribution network.

[90] Energy Information Administration, *Electricity Prices in a Competitive Market*, Op. Cit. pp. 15-16, 90-91, and 95.

Figure 6
PJM Total Capacity Market



The supply curve for capacity increases gradually throughout 95 to 99 percent of the hours in a year. However, the supply curve for reserve capacity becomes price inelastic during a few periods throughout the year.

The completely price inelastic demand curve, along with the highly inelastic supply curve, results in a market subject to occasional price spikes. Figure 6 also depicts an "economic demand curve" which is the demand for reserve margin derived from customer's WTP for reliability. This ordinary demand curve reflects the law of demand and shows that consumers are willing to purchase less reliability at higher prices. This demand curve depicts a lower level of optimum reserves, relative to the political demand curve, and reduced capacity costs for customers.

One approach to obtaining price-demand response in the market for total capacity is to infer an economic demand curve for reliability. As a first approximation, the empirical evidence could be obtained from the Energy Journal Special Issue

In addition, price-demand response in the capacity market would result from a price-demand response in the energy market. The demand for capacity is derived from the demand for energy. An energy market price-demand response automatically produces a corresponding price-demand response in the capacity market. An economic demand curve for capacity, that also reflects price-demand response for energy, would have more price elasticity than reflected in Figure 6.

6.5 The Benefits of Optimum Reserve Margin

Applying an economic demand curve to obtain reserve capacity would improve the overall efficiency of the electricity market and contribute at least three significant benefits to customers:

1. A direct benefit to customers in the form of increased consumer surplus.

2. A decrease in price spikes in the wholesale capacity market and in other markets
3. A reduction in required capacity

A price-demand response mechanism for required capacity would produce these three benefits, for exactly the same reasons that efficient retail pricing produces these benefits. Customers who require less reliable service, or who can provide their own peak service, would enjoy a decrease in rates and hence an increase in net benefits from consuming electricity. The customers who prefer to pay for less reliable service, would no longer subsidize customers willing to pay for higher quality service.

Some customers may prefer an increase in power reliability for their computer systems, but less reliability for other electricity using devices. Such customers would purchase the less reliable service from the network and obtain improved reliability for their computer systems at the end use level. Surge protectors and backup power supplies are already widely available for home and office computer systems.

The incentive under the regulation is apparently towards sub-optimal reserve margins. Purchasing reserve margins that reflected customers' preferences would directly add value to customers. Introducing price responsiveness to determining total reserves would reduce capacity costs and thereby reduce rates to customers. Further, if customers were offered choices of increased or decreased reliability, such choice would add further value.

On occasion price spikes in the PJM region have produced prices up to 10 times non-peak prices. The PJM Market Monitoring Unit notes that these price spikes are the result of market power in the capacity market. More correctly, these price spikes are the result of a relatively fixed amount of generation capacity at specific locations, coupled with the complete insensitivity of demand to higher prices. However, a major contributing factor to these price spikes is the commitment by the PJM power pool to obtain a large capacity reserve margin regardless of cost. A price-demand response serves as a shock absorber. As prices increase, part of the shock is absorbed by a decline in the quantity demanded, which reduces pressure for further price increases.

Introducing an economic demand curve in the capacity market would add substitutability and flexibility that reduces total required reserve capacity. The result is a reduction in capital costs and lower electricity prices.

6.6 PJM's Demand Side Management Program

The PJM region is attempting to use demand side management (DSM) to reduce load during peak periods. This DSM program is referenced briefly in the recent MMU Report and described in greater detail in a report to the FERC.[91] During the summer of 2000, PJM began a Customer Load

[91] PJM Market Monitoring Unit, 2002 State of the Market, PJM Interconnection, March 5, 2003, pp. 5, 19, 76, and PJM Market Monitoring Unit, *PJM 2002 Load Response Program,* A Report to the Federal Regulatory Commission, May 31, 2003.

Reduction Pilot Program designed to reduce load during critical peak periods by compensating customers for measurable load reduction. FERC approved this Pilot Program, but high peak demand did not materialize during the summer of 2000, and customers were not compensated.

In 2001-2002 a load reduction program was implemented and approved by FERC. This program includes and *economic option* and an *emergency option*. In the economic option, end use customers are compensated under contract to voluntary reduce load during periods of high prices. In the emergency option program, the system operator has the option of calling for the agreed upon reduction in load. In the economic option load reduction by the participant is voluntary; in the emergency option load reduction is mandatory when called by the system operator. In the active load management program, individual customers contract with LSE to be willing to reduce their load by specified amounts during critical periods. Customers may reduce their load by using on-site generators to make up the load, or, by not have alternative supply and simply reducing their power needs. By contracting with customers to reduce peak load, the LSE obtains a capacity credit that reduces the LSE's capacity obligation. Capacity required to meet peak demand is thereby reduced.

The amount of capacity credit has not increased significantly since 1999. Total active load management capacity resources were 1,962 MW in 2001, a decline from the 2,005 MW resources in 1999. In 2002 much of these capacity resources switched to the Pilot Program mentioned above. This program was introduced during the summer of 2000 showed only a modest success by 2002. During 2001, total load reduced under the Pilot Program was about 440 MW with an average payment of $682/MWh. Considering that the maximum total load in the region is about 63,762 MW, the total load management program of roughly 2,000 MW is less than optimal.

The average payment per MWh provides one indication of the cost-effectiveness of demand side load reductions. In 2002 (Table 6) average payment in the economics option to participants was $118/MWh (or 11.8 cents/kWh). However, in 2002 payment to participants in the emergency option was $514/MWh (51.4 cents/kWh).

Table 6

Load Reductions and Payments for PJM Economic and Emergency Programs, 2001 – 2001

Total Load Reduction (MWh)	**2001**	**2002**
Economic	50	6,462
Emergency	393	551
Total	442	7,013
Total Payment		
Economic	$13,994	$761,977
Emergency	$287,514	$282,756
Total	$301,508	$1,044,734
Average Payments ($/MWh)		
Economic	$283	$118
Emergency	$732	$514
Total	$682	$149

Source: PJM Monitoring Unit, *PJM 2002Load Response Program*, A Report to the Federal Energy Regulatory Commission, May 31, 2003.

In the emergency option, the PJM pool agrees to pay participants $500 per MWh, or the location marginal price, whichever is higher. The MMU now explicitly recognizes that this price exceeds the economic value of load reduction. The MMU states: "…it is clear that the marginal value to the system was less than the $500 per MWh paid to the resources for reducing load." [92] The emergency option appears not to be cost-effective because of minimal participation, and because the cost of reducing demand is too high.

The emergency option provides incentives that are inherently inefficient. In a study of the income distribution effects of utility DSM programs, I explained that utility energy conservation subsidies had their greatest appeal, and provided the greatest benefits, to those participants who saved the least amount of energy.[93] Similarly, those households that could save a relatively large amount of energy derived little benefit from the subsidy programs and were not inclined to participate. The

[92] PJM Market Monitoring Unit, *PJM 2002 Load Response Program*, A Report to the Federal Regulatory Commission, May 31, 2003, p. 10.

[93] Ronald J. Sutherland, "Income Distribution Effects of Electric Utility DSM Programs" *The Energy Journal*, Vol. 15, No. 4, 1994, pp. 103-118.

incentive inherent in the subsidy program is to attract exactly the wrong participants. This perverse incentive is not linked to energy conservation, but is a simple application of microeconomics.

The data in the above table indicate that payments for emergency energy are more than four times the payments for the same kWh of economic energy. The explanation follows from the above economic principle of subsidies. Participants in the emergency energy program receive at least $500 per MWh to reduce load. Those who are inclined to participate are those who can reduce load at lowest cost. Such participants receive significant consumer surplus (free money) from the subsidy program, which is, of course, their incentive to participate. The program has the greatest appeal and greatest benefit to those who reduce load at the lowest cost. However, payment for reducing load is set at a minimum of $500 per MWh, which thereby provides large benefits to participants and large costs to ultimate customers. This program provides benefits to customers in excess of their marginal cost, which means that it is not cost effective for ratepayers.

The economic program is an auction market and it attracts participants at the marginal cost of the last participant. This program reduces energy use at a much lower cost than the emergency program, as confirmed by the above program.

The amount of capacity credit has not increased continuously since its first year in 1999. Total PJM capacity resources in their load management program were 1,962 MW in 2001, a decline form the 2,005 MW resources in 1999. During 2001, total load reduced under the Pilot Program was about 440 MW with an average payment of $682/MWh. Maximum total load in the region is about 63,762 MW. The PJM program is reducing some capacity, but thus far at a high price.

7. Concluding Comments

The purpose of the previous section is to determine the benefits to customers from restructuring the market for total capacity. Thus far, this market has not been restructured in a competitive direction. Capacity reserve margins are determined by a rule and are not price sensitive. PJM has however made an effort to buy options to reduce demand and hence capacity at critical peak periods. The effort obtains about 2,000 MW of capacity, but a high subsidized price of at least $500/MWh.

Certainly, PJM could apply a price sensitive reliability demand curve that reflects customer interests, instead of a price inelastic demand curve. An additional approach to reducing capacity prices at peak periods is to introduce real time pricing in the retail energy market. However, this approach requires state utility commission action, rather than PJM action. A price-demand response in the energy market automatically produces a price-demand response in the capacity market.

This report emphasizes that interest groups may impair restructuring in an economically efficient direction. The political demand curve for capacity reflects the political reality that super high reliability is required. Should the PJM system experience outages, or some other lack of reliability, the entire restructuring experiment could be jeopardized. An economically optimum reserve margin, with bad luck, could prove to be uneconomic.

The restructuring of electric utilities was, until a few years ago, characterized by optimism and the expectation of very large benefits for ultimate customers and the regional economy. Such benefits are achieved by the deregulation of other industries. Further, the historical experience with utility regulation confirms that significant benefits are achievable with the restructuring of electricity markets. Every piece of evidence reviewed here indicates that the potential benefits from restructuring are large, if not enormous. Ultimately, the states that restructure successfully will be increasingly competitive with non-restructuring states.

However, achieving these benefits is more difficult than initially expected, and requires a longer time frame.[94] The long time frame results primarily from stranded cost recovery, lags in investing in new generating capacity, and from the challenge of successfully implementing price-demand response at the retail level. Influential interest groups and political risks of restructuring add to the challenge.

Participants in the working group advising on this project inquired about the implications of the benefit estimates here for those states not choosing to restructure. Much of the success in the PJM region is coming in the wholesale market, and results from FERC and PJM interchange efforts. An important development in other regions would be the development of regional power pools, which FERC is encouraging. A major milestone in achieving an efficient market is the successful development of a wholesale auction market. FERC is encouraging the development of regional transmission organizations. The evolution of such markets into power pools with real time prices

[94] This long time frame require to achieve all potential benefits is emphasized by Clifford Winston, op. cit. 1998, and by Paul Joskow, op. cit. 1997.

"discovered" in auction markets would be an important step in restructuring wholesale markets in a competitive direction.

The implication with respect to developing retail competition in currently inactive states is more problematic. The states pushing forward with restructuring are gaining a "first mover advantage", in that the PJM states are incurring some cost reductions that are not being obtained in other states. However, these PJM states have not implemented a retail competitive model that includes efficient pricing and various energy related services. States that are pursuing the "wait and see" strategy to restructuring, may avoid implementing imperfect models, and may be able to catch up after a highly successful retail model is demonstrated. But this "catch up" strategy may not succeed. In this study, we have quoted serious scholars in the field of regulation: Winston, Joskow and Borenstein. Each emphasizes that the largest benefits from restructuring are distributed over many years.

Retail competition imposes costs and risks both if it is implemented, and if it is not implemented. At present, there is limited incentive and significant aversion to implementing competition is several states. However, by not restructuring in a competitive direction, there is a risk of being left behind in that restructuring states are achieving competitive advantages that cannot be regained.

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